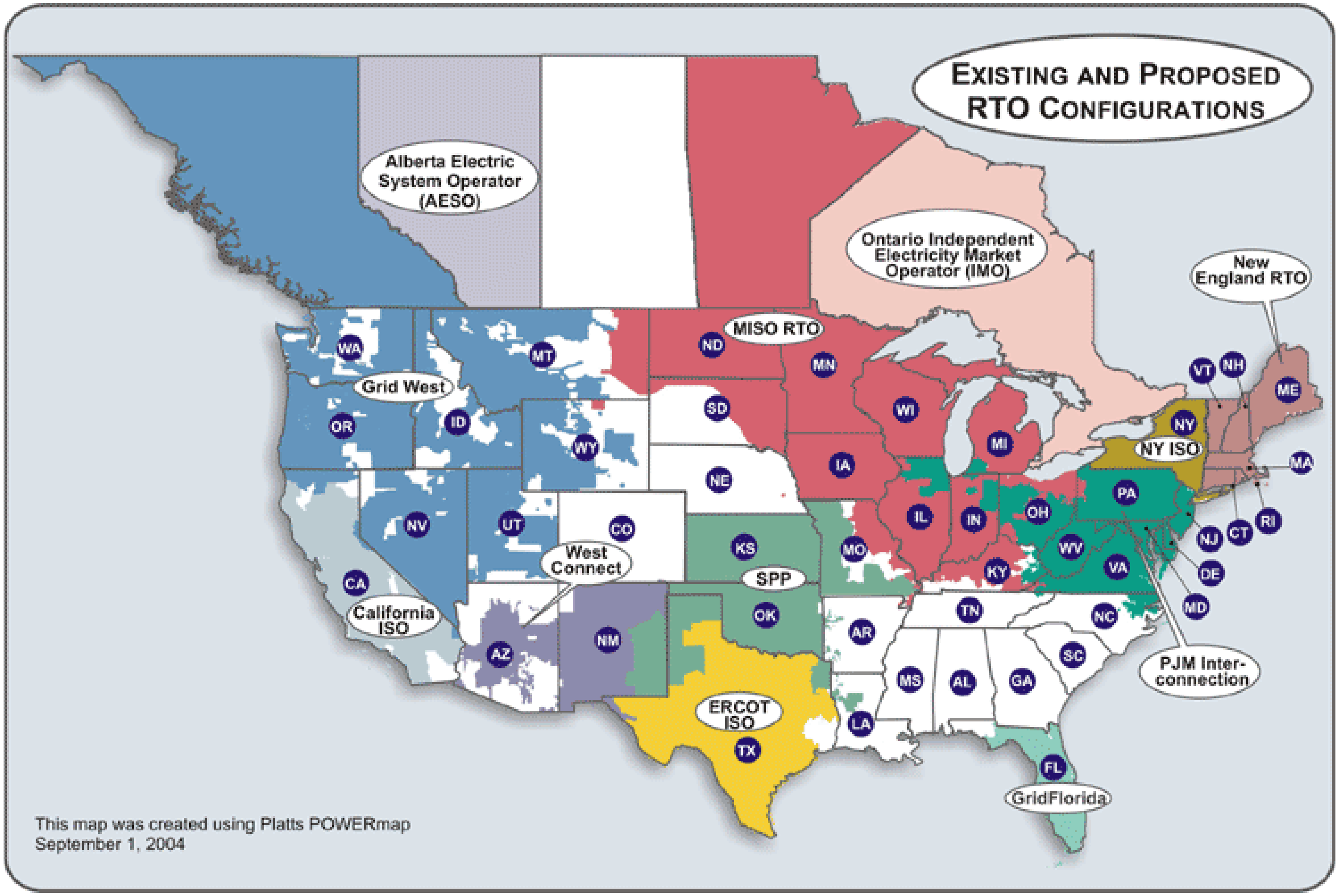
RTO-ISO Handbook



DISCLAIMER: While every effort has been taken to verify the accuracy of the content of the RTO-ISO Handbook and proper operation of this site, the information contained in this RTO-ISO Handbook is for general guidance only. The information on this site should not be used as a substitute for the original source of rules, regulations, and policies governing Regional Transmission Organizations and Independent System Operators.

Organization	Summary	Research
CAISO	CAISO's Tariff is current through August 10, 2004. On June 22, 2004, the U.S. Court of Appeals for the District of Columbia held that the Commission has no authority to dictate the governing structure of an ISO. The Governor makes appointments to the Governing Board. Five members are on the Governing Board. All powers and activities of CAISO are exercised and managed by the Governing Board, or under its delegation. Under California law, not more than forty-nine percent of the Governing Board may be "interested persons." A quorum for any Board meeting will be two-thirds of the Governors then in office. The affirmative vote of a majority of the Governors then in office, subject to recusal and a Governor's right to appeal certain state-jurisdictional matters, will	The CAISO Tariff is current through August 10, 2004. The Tariff includes all currently effective language from Commission-approved Tariff Amendments and compliance filings made consistent with Commission orders. On June 22, 2004, the U.S. Court of Appeals for the District of Columbia held that the Commission has no authority to dictate the governing structure of an ISO. The court said that if the Commission does not think the governing structure meets the independence requirements for an ISO then the Commission's recourse is to declare CAISO is not an ISO. As a result, the current governance structure can remain in place, although the Commission has declared that it does not meet the independence standards for an ISO and this has repercussions in other areas for CAISO, *e.g. see* issue #14. The top tier will consist of an independent, non-stakeholder Board, while the lower tier will consist of an advisory committee of stakeholders, which may recommend options to the Board, and an advisory committee of the California Electricity Oversight Board (EOB) which will serve the state of California and its agencies representatives in advising the Board. The top tier will have sole decision-making authority in all matters. CAISO currently employs the following governance structure: <u>Governing Board</u>- The Governor of the State of California makes appointments to the Governing Board. By-laws, Article III, section 4.1. Each appointee becomes a member of the Governing Board unless the State Oversight Authority[1] declines to confirm the appointee. By-laws, Article III, section 4.1. The term of each member of the Governing Board is one year. By-laws, Article III, section 6. <u>Number</u> - Five (5) members are on the Governing Board. By-laws, Article III, section 2. The State Oversight Authority is charged with appointing a Chairperson for the Board. By-laws, Article III, section 4.3.

[1] 'State Oversight Authority' shall mean, for such period as California is the only Participating State, that certain Electricity Oversight Board described in Sections 335 to 340 of the California Public Utility Code, as in effect from time to time; and thereafter, such body or bodies as determined by any applicable law or regulation of Participating States and applicable Federal law or regulation. By-laws, Article III, Section 3.3.

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	be the act of the Governing Board. Board members may not be affiliated with any actual or potential participant in the CAISO Market.	<u>Qualifications</u> - No member of the Governing Board will be affiliated with any actual or potential participant in any market administered by CAISO. By-laws, Article III, section 4.2. <u>Powers</u> - All powers and activities of CAISO are exercised and managed by the Governing Board or, if delegated, under the direction of the Board. By-laws, Article III, section 1. <u>Chairperson</u> - EOB will appoint a Chairperson of the Governing Board. The Chairperson is chosen from among the members of the Governing Board. By-laws, Article III, section 4.3. <u>Vacancies and Removal</u> - A resignation is effective upon receipt of written notice by the Chairperson, the President or the secretary. By-laws, Article III, section 7. The Governing Board may remove any Governor, with or without cause, if at least two-thirds (2/3) of the Governors then in office vote in favor of such removal, with the approval of EOB. By-laws, Article III, section 7. <u>Interested Persons Limit</u> - In accordance with section 5227 of the California Nonprofit Corporation Law, not more than forty-nine (49) percent of the persons serving on CAISO's Governing Board may be interested persons. "Interested persons" means either: Any person currently being compensated by CAISO for services rendered to it within the previous twelve (12) months, whether full- or part-time, independent contractor, or otherwise excluding any reasonable compensation paid to a director as a director; or any brother, sister, ancestor, descendant, spouse, brother-in-law, sister-in-law, son-in-law, daughter-in-law, mother-in-law or father-in-law. By-laws, Article III, section 18.1. <u>Quorum</u> - A quorum for any meeting of the Governing Board will be two-thirds (2/3) of Governors then in office. By-laws, Article III, section 12. <u>Voting</u> - Except where a greater number is required by the Articles of Incorporation, by applicable law or the By-laws, the affirmative vote of a majority of the Governors then in office, subject to recusal and a Governor's right to appeal certain state-jurisdictional matters, will be the act of the Governing Board. By-laws, Article III, section 13.1. <u>Independence</u> - As stated previously, no member of the Governing Board will be

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		affiliated with any actual or potential participant in any market administered by CAISO. By-laws, Article III, section 4.2. Governors Code of Conduct - The Governing Board will ensure that each Governor complies with the Governors Code of Conduct, which is attached to the By-law as Exhibit A. By-laws, Article III, section 14.5. Committees - The Governing Board may, by resolution adopted by two-thirds of the Governors then in office, designate one (1) or more committees, each consisting of two (2) or more Governors, to serve at the pleasure of the Board. By-laws, Article IV, section 1. The By-laws list the following committees: (1) Advisory Committees; (2) ADR Committee; and (3) Audit Committee. Governors Interest in markets - Subject to a limited number of exceptions, the Governing Board shall not approve a transaction to which CAISO is a party, and in which one or more Governors or their employers has a material financial interest. By-laws, Article III, Section 15.2.
MISO	Seven members are on the Board of Directors. Each Director serves a three-year term. A Director may be removed for cause. Five Directors constitutes a quorum. Twenty-five percent of Members constitutes a quorum in a Members meeting. Board members are precluded from serving as director, officer or employee of a Member two years prior to, and two years after serving as a Director. There are two stakeholder committees – an Advisory Committee and an Owners	Board of Directors – The Board of Directors consists of seven (7) members plus the President, elected by Members by a single vote for each position from among a group of candidates selected by an independent executive search firm. The first Board of Directors candidate group must include no fewer than two (2) candidates for each position. Initial terms are staggered, with two Directors serving for one year, two Directors serving for two years, and the final three Directors serving for three years. Agreement of Transmission Facilities Owners to Organize the Midwest ISO, Article Two (Issued November 20, 2000), Midwest ISO FERC Electric Tariff, First Revised Rate Schedule No. 1, Original Sheet No. 22, accepted by the Commission on September 16, 1998. After the initial set up of the Board, each Director shall serve a three-year term, except those elected by the Board to fill a vacancy in the remainder of a term. Before a term expires, a nominating committee consisting of three Board Members whose terms are not expiring and two members of the Advisory Committee must select an executive search firm to provide at least two qualified candidates to the nominating committee for each open Director position. Members may also submit candidates. At least 30 days prior to the meeting of Members and Directors at which Directors are elected, the Board must provide the name and qualifications of one (1) candidate for each open position. That candidate must be elected by a majority of votes cast. Agreement of Transmission

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	Committee. The Board is authorized to revise or expand stakeholder groups.	Facilities Owners to Organize the Midwest ISO, Article Two, Midwest ISO FERC Electric Tariff, First Revised Rate Schedule No. 1, First Revised Rate Sheet No. 23-24. The Board selects from among its members a Chairman. Agreement of Transmission Facilities Owners to Organize the Midwest ISO, Article Two, Midwest ISO FERC Electric Tariff, First Revised Rate Schedule No. 1, Original Sheet No. 24-A. A Board member may be removed for cause upon production of a petition signed by twenty percent of all Members and a subsequent majority vote of the Members. Agreement of Transmission Facilities Owners to Organize the Midwest ISO, Article Two, Midwest ISO FERC Electric Tariff, First Revised Rate Schedule No. 1, Original Sheets No. 25-26. Qualifications - Of the seven candidates, four must have expertise and experience in senior management corporate leadership, or in finance, accounting, engineering or utility laws and regulation. Of the other three Directors: one must have expertise and experience in the operation of transmission; one must have expertise in transmission planning; and one must have expertise in commercial markets, trading and risk management. Agreement of Transmission Facilities Owners to Organize the Midwest ISO, Article Two, Midwest ISO FERC Electric Tariff, First Revised Rate Schedule No. 1, Original Sheet No. 22, First Revised Rate Sheet No. 23. Supermajority - Five Directors constitutes a quorum of the Board. Agreement of Transmission Facilities Owners to Organize the Midwest ISO, Article Two, Midwest ISO FERC Electric Tariff, First Revised Rate Schedule No. 1, First Revised Rate Sheet No. 30. At Member meetings, a majority of votes cast by Members at a meeting controls. A quorum requires 25 percent of members (or proxies). Each Member may cast one vote. Agreement of Transmission Facilities Owners to Organize the Midwest ISO, Article Two, Midwest ISO FERC Electric Tariff, First Revised Rate Schedule No. 1, First Revised Rate Sheet No. 41. Independence - Within two years prior to or subsequent to election to the Board, no Board member shall have been a director, officer, or employee of a Member, user or affiliate. During service, and for two years after service as a Director, no Board member may have a material business relationship or other affiliation with any Member or User or an affiliate of a Member or User. Participation in a pension plan is not deemed a material relationship if the plan does not involve ownership of securities of

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		the company sponsoring the plan. Agreement of Transmission Facilities Owners to Organize the Midwest ISO, Article Two, Midwest ISO FERC Electric Tariff, First Revised Rate Schedule No. 1, Original Sheet No. 22, First Revised Rate Sheet No. 23. Stakeholders - There are two stakeholder committees – an Advisory Committee and an Owners Committee. The Advisory Committee consists of twenty-three representatives, three representatives of owners; three representatives of municipals or cooperatives and transmission-dependent utilities; three representatives of independent power producers and exempt wholesale generators; three power marketers; three eligible end-use customers; three representatives of state regulatory authorities; two representatives of public consumer groups; two representatives of environmental and other stakeholder groups; and, one representative Member (being unable to transfer operational control to Midwest ISO) who has entered into a coordination agreement with Midwest ISO. All categories (except the final category) must include one representative seat assigned to a MAPP member. The Board is authorized to revise or expand stakeholder groups, and must facilitate quarterly meetings with the Advisory Committee. The Owners Committee consists of one person representing each of the Owners. Agreement of Transmission Facilities Owners to Organize the Midwest ISO, Article Two, Midwest ISO FERC Electric Tariff, First Revised Rate Schedule No. 1, First Revised Rate Sheet No. 43-45, Second Revised Rate Sheet No. 46. *See also Midwest ISO*, 84 FERC ¶ 61,231 (1998) (approving governance structure*); Int'l Transmission Co*., 97 FERC ¶ 61,328 (2001) (Independent transmission companies (ITCs) within Midwest ISO are required to demonstrate that their respective governance structure are independent of any market participant, and that Appendix I under the Midwest ISO TO Agreement preserves Midwest ISO's role as regional security coordinator and its functions under Appendix E, section V of the Midwest ISO Agreement).
NYISO	Ten member Board of Directors. Board members possess a cross section of skills and experiences. Board is responsible for operation of ISO and administration of ISO tariff Board is self-perpetuating and any	Articles 4, 5, and 7 of the ISO Agreement (*see also* 88 FERC ¶ 61,229 (1999) provide for the organizational structure for the ISO, as well as the composition of the ISO Board and the ISO's various voting structures. Board of Directors - NYISO is governed by a 10-person unaffiliated Board of Directors, of which one board member is designated as the President (Chairperson) and he/she will manage the day-to-day operation of the ISO. The President is chosen by the other 9 Directors. Attendance or participation by 6 Directors should constitute a quorum, and an affirmative vote by 6 Directors is required to pass a measure.

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	vacancies on the Board shall be filled by the existing Directors There are three standing committees, including: (1) the Management Committee; (2) Operating Committee; and the (3) Business Issues Committee. Committee members vote on a sector basis All revisions to the ISO's Tariffs and agreements require the ISO to obtain concurrence from the Management Committee.	The initial Board was formed by using an 18-member stakeholder selection committee which selected the 9 initial members of the Board. In turn, the 9 Directors selected the President (the 10th member). The ISO Board has ultimate responsibility for the operation of the ISO and administration of the ISO Tariff. The ISO may assign a representative to attend meetings on a non-voting basis. The ISO Board representative may propose committee actions and appeal committee actions. The ISO Agreement requires that the Directors possess a cross-section of skills and experience (e.g., electric utility management, experience in Commission regulatory affairs, corporate finance, public policy, consumer advocacy, environmental affairs, and business management and information systems). At least three Directors must have relevant electric industry experience. The qualifications of the President must include extensive experience in the operation of electric power systems and in management. The ISO Board will be self-perpetuating and any vacancies on the Board shall be filled by the existing Directors. The new Directors shall be required to meet the same basic qualifications as the initial Directors. The Management Committee may assist board in filling vacancies by recommending candidates. The process of selecting new Directors shall be subject to Commission approval. Committee Structure - Aside and apart from the Board of Directors, the core of NYISO's governance is centered around its three standing committees, including: (1) the Management Committee; (2) Operating Committee; and the (3) Business Issues Committee. Each committee oversees its own set of working groups and/or subcommittees. The Management Committee reports to the Board, whereas the other committees report to the Management Committee. The vote required to approve a measure before the Management Committee (which reviews the work of the Operating and Business Issues committees and reviews appeals from actions taken by these committees) requires 58 percent of total votes cast. Committee members vote on a sector basis. The five sectors include: (1) Transmission Owners (20 percent, (2) Generator Owners (21.5 percent), (3) End Use Consumers (20 percent), (4) Other Suppliers (21.5 percent), and (5) Public Power / Environmental (17 percent). If qualified, any party of an affiliate may participate in more than one sector. However, any party of an affiliate may only vote in one sector. A party may also split its vote within a chosen sector.

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		Within a sector, 58 percent of the vote is required to pass a motion. For Management Committee Action, at least 5 members, or 50 percent of a sector, (whichever is less) shall constitute a quorum. The Management Committee is comprised of various sectors with corresponding voting percentages. Actions of the Management Committee may be appealed to the ISO Board by any voting or non-voting party of the Management Committee or may be reviewed and acted upon by the ISO Board upon its own motion. The ISO Board has the authority to overrule a decision of the Management Committee. All revisions to the ISO's Tariffs and agreements require the ISO to obtain concurrence from the Management Committee. The ISO may unilaterally make section 205 filings with the Commission, without concurrence of the Management Committee when necessary to address exigent circumstances related to the New York ISO market or the reliability of the grid, which would be effective for 120 days. Any party is free to make a section 206 filing at any time.
ISO-NE	The Commission has conditionally approved ISO-NE to become and RTO. ISO-NE administers System Rules and Procedures. ISO-NE has an Independent Board. ISO-NE and NEPOOL have a Service Agreement defining the duties of each party. ISO-NE's self-perpetuating Board is selected by a search Committee. Board members possess a cross-section of skills. ISO-NE has 10 Board members. ISO-NE directors and family members must be independent of market	The Commission conditionally approved ISO-NE to become an RTO in ISO New England Inc., 106 FERC ¶ 61,280 (2004). On November 3, 2004, the Commission conditionally approved the ISO-NE RTO Tariff, which includes mostly provisions previously accepted by the Commission under the ISO-NE/NEPOOL arrangements. ISO-NE's current tariff is valid until it begins RTO operations, which will be at least 30 days following Notice to the Commission that the Participating Transmission Owners have unanimously agreed to place the ISO-NE RTO operations into effect. ISO New England Inc., 109 FERC ¶ 61,147 (2004). <u>Powers</u> - ISO-NE has sole authority to interpret and administer System Rules and Procedures for operating functions. Restated NEPOOL Agreement, section 6, Original Sheets No. 68-88. <u>Independence</u> - ISO-NE has an Independent Board that has authority over its budget and the authority to plan for and operate the System in accordance with System Rules and procedures. ISO Agreement, section 1.4. ISO-NE and NEPOOL have a Service Agreement (SA) that defines the duties of each party. The SA maintains an "arm's length" relationship between NEPOOL and ISO-NE. ISO-NE and NEPOOL use a consultative process to develop reliability or market rules/changes in rules. However, FERC has stated that the relationship between ISO-

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	participants. The ISO-NE Board Advisory Committee is comprised of 20-25 members. NEPOOL, which develops rules for system reliability and market operations, is comprised of four principal committees with five sectors each. ISO-NE has an active role in NEPOOL actions. All sectors have equal voting power. Each NEPOOL Participant may appoint a member to the Management Committee. ISO-NE Board members must be independent of NEPOOL Participants.	NE and NEPOOL does not meet its "independence" characteristic under Order No. 2000. Restated NEPOOL Agreement, section 6, Original Sheets No. 68-88. Selection Process - The selection process for the ISO-NE Board begins with a search committee consisting of a NEPOOL executive committee, New England Conference of Public Utility Commissioners, and an outside attorney for ISO-NE. An independent research firm identifies candidates from a diverse pool, with selections made by consensus. Following the initial selection, the Board is self-perpetuating. Vacancies are filled by action of the remaining Board members. *See New England Power Pool*, 79 FERC ¶ 61,374 (1997). Qualifications - Board members possess a cross-section of skills including FERC experience in utility operation or regulation, law, bulk power systems, human resource administration, power pool operations, public policy, consumer advocacy, environmental affairs, business management, information systems, and corporate finance. Number - There are 10 Board members, all chosen by the NEPOOL Executive Committee. ISO Agreement, section 5.2, Page 8. Conflicts of Interest - ISO-NE directors and family members: must not own any securities of a market participant; such securities must be divested within a year of election to the board; and may not be a director, officer, employee, or partner of a market participant. An ISO-NE director cannot: be a former executive officer of a NEPOOL participant that has 3 percent of the voting shares on the NEPOOL management committee; receive continuing benefits under an existing employee benefit plan; have a material ongoing business or professional relationship with a market participant; and participate in any energy transactions within ISO-NE markets. ISO Agreement, section 5, Page 7. Committees - The principal ISO-NE stakeholder committee is the Board Advisory Committee, which is comprised of 20-25 stakeholders from New England; their role is to advise the Board on a variety of issues. ISO Agreement, section 5.6, Page 10. NEPOOL develops rules for system reliability and market operations and has its own governance structure which is comprised of four principal committees: (1) Participants' Committee; (2) Market Committee; (3) Tariff Committee; and (4) Reliability Committee. Each committee has five sectors: (1) transmission owners; (2) generators; (3) marketers/brokers; (4) public power; and (5) end user). There also is a separate

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		Transmission Owners' Committee. *See New England Power Pool*, 79 FERC ¶ 61,374. ISO-NE can appoint a non-voting member to the NEPOOL Committees and ISO-NE has an active role in the actions taken. If a NEPOOL Committee fails to adopt an ISO-NE proposal, or ISO-NE is opposed to a rule change, ISO-NE can appeal. *Id.* All active sectors will have equal aggregate votes on their committees and, within each sector; each voting member will have an equal per capita vote. *See New England Power Pool*, 88 FERC ¶ 61,079 (1999). Each NEPOOL Participant is entitled to appoint a member to the Management Committee. After review of reports or actions of ISO-NE and other planning committees, may establish or approve proper standards of reliability for the bulk power supply of NEPOOL. *See New England Power Pool*, 79 FERC ¶ 61,374. <u>Code of Conduct</u> - ISO-NE's Code of Conduct prohibits any ISO-NE Board member or any officer or employee of ISO-NE from being an officer, director, partner or employee of any NEPOOL participant. The policy also provides that, subject to a short transition period not to exceed six months, no director or officer or employee of ISO-NE will have a material financial interest in the economic performance of any NEPOOL Participant or other market participant in the NEPOOL control area, or any affiliate of either. *Id*.
PJM	PJM Tariff current through April 1, 2002; PJM Operating Agreement current through September 29, 2003. Independent Board consists of 9 members, elected by the Nominating Committee and presented to the Members Committee for voting. A sector voting structure involves stakeholders in nomination decisions. The Members Committee consists of parties to the Operating Agreements, from all sectors with at least 5 members.	<u>Board of Directors</u> - Independent Board; candidates selected by an independent consultant. If the Members Committee fails to elect a full Board from the nominees proposed, the Nominating Committee will propose a further nominee from the list supplied by the independent consultant for each remaining vacancy. Operating Agreement (OA), 7.1. <u>Number</u> - Nine Independent Board Members elected by the Nominating Committee and presented to the Members Committee for voting. OA, 7.1. <u>Qualifications</u> - Expertise and experience in the areas of corporate leadership at senior management or board of directors level; or in finance, accounting, engineering, or utility laws and regulation, transmission dependent utilities, operation and planning of transmission systems, commercial markets and trading and risk management. OA, 7.2. <u>Supermajority</u> - Election Requirements for Board Chair and Vice Chair of Members Committee requires only a simple majority vote rather than a two-thirds majority. The

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	All officers, employees, and Board members are prohibited from maintaining interests in any market participant.	sum of affirmative sector votes necessary to pass motions must be greater than the product of 0.667 times the number of sectors meeting the minimum membership requirements. OA, 8.4. Independence - The Nominating Committee includes stakeholders. Each stakeholder class is represented by one member and two members of the existing Board serve on the Nominating Committee as voting members (and a third as a non-voting representative). OA, 7.1. The full Members Committee will vote to elect Board Members. Additionally, the Nominating Committee will present one nominee for each open Board seat to prevent electioneering. OA, 8.8. Stakeholder involvement - Sector voting structure. The Nomination decisions and election are controlled by the stakeholder's representatives. The Nominating Committee will consist of one representative elected annually for each sector of the Members Committee. Each voting member shall be entitled to cast one vote in its sector. OA, 8.1. *See P.J.M. Interconnection, L.L.C.*, 102 FERC ¶ 61,188 (2003). Tariff and market rule changes - The Members Committee will consist of parties to the PJM Operating Agreement. The Members Committee will consist of all sectors. In order for a sector to be represented on the Members Committee with voting rights, it must have at least 5 members. A member can belong to only one sector and is limited to one vote within that sector. OA, 8.1. Each sector shall be entitled to cast one vote, which can be split into factional components voting either for or against a measure. OA, 8.4. Transmission Owners may file changes to non-rate terms and conditions under section 205 if the proposed changes are not rejected by a majority of the Board, and any such rejected changes may be filed under section 206. OA 7.7(vii). Interest in markets - Code of Conduct that prohibits an employee from disclosing market-sensitive information and from accepting gifts and favors that could raise conflict of interest concerns. All officers, employees, and PJM Board members must divest their interests in any market participant within six months of their hire or election. *Pennsylvania-New Jersey-Maryland Interconnection, et al.*, 81 FERC ¶ 61,257, at 62,265-66 (1997).

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		With certain exceptions, the OA and any Schedules may be amended, or a new Schedule may be created, only upon; (i) submission of the proposed amendment to the Board for its review and comments; (ii) approval of the amendment or new Schedule by the Members Committee, after consideration of the comments of the Board, in accordance with OA section 8.4, or written agreement to an amendment of all Members not in default at the time the amendment is agreed upon; and (iii) approval and/or acceptance for filing of the amendment by the Commission and any other regulatory body with jurisdiction as may be required by law. OA, 18.6.
SPP	The Board of Directs consists of seven independent members. Each Director serves a three-year term. Five Directors constitutes a quorum. Directors are prohibited from being a director, officer, or employee of, or having a direct business relationship, affiliation, or financial interest in a member or customer of SPP. A Director may be removed for cause by a majority vote of each Membership sector at a meeting of Members. A Members Committee, made up of representatives from participating Members, advises the Board of Directors. Several Committees report to the Board of Directors: Markets and Operations Policy, Strategic Planning, Human Resources, Compliance, Finance, and Corporate Governance.	<u>Board of Directors</u> – The Board of Directors consists of seven members, each of whom must be independent of any SPP Member. The President and Chairman of the Board of SPP are selected from the seven Directors. Initially, SPPs current independent and non-stakeholder Board members will comprise the first Board of Directors. Initially, their terms will be staggered by lottery, with two Directors serving a one-year term, two directors serving a two-year term, and two directors serving a three-year term. *See* SPP Revised Bylaws, filed with October 2003 RTO filing, Docket Nos. RT04-1-000 and ER04-48-000, at § 4. Pursuant to *Southwest Power Pool Inc.*, 106 FERC ¶ 61,110 (2004) ("RTO Order"), the SPP installed the independent and non-stakeholder board on May 1, 2004. Following the initial terms described above, Directors will be elected to serve three-year terms. At least three months before a meeting of Members where the election of new Directors will be necessary, the Corporate Governance Committee (described below) must begin the process of nominating persons for Director positions. Each sector of Membership votes separately, with the result for each sector being a percent of approving votes. The candidates with the highest approving vote percentage will fill the Director vacancies. *See* Revised Bylaws at § 4.3. In response to the Commission's requirement, SPP codified in its Bylaws the process that will be followed to determine how potential Board nominees will be selected, *e.g.* through the use of an independent search firm, etc. Specifically, SPP added new section 6.6b to the Bylaws, which confirms that potential Board of Directors nominees will be selected using an independent search firm. *See Southwest Power Pool*, *Inc.*, 108 FERC ¶ 61,003 at P 38 (2004).

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	A Regional State Committee, including one member from each state regulatory commission, provides "direction and input," and has primary responsibility for determining regional proposals and the transition process in four areas (see description).	A Chair and Vice Chair are elected from the Board of Directors and serve two-year terms. The President of SPP may not also serve as Chairman. Revised Bylaws at § 4.6.2. A Director may be removed for cause by a majority vote of each Membership sector at a meeting of the Members. To initiate removal proceedings, a petition stating the specific grounds for removal must be signed by at least 20 percent of the Members. *Id.* at § 4.4. <u>Qualifications</u> – Directors must have "recent and relevant senior management expertise and experience in one or more of the following disciplines: finance, accounting, electric transmission or generation planning or operation, law and regulation, commercial markets, and trading and associated risk management." *Id.* at § 4.2.2. <u>Independence/Conflicts of Interest</u> – Directors are prohibited from serving as the director or officer of a Member or customer of services provided by SPP. Also, Directors may not be employed by or have a direct business relationship, financial interest or other affiliation with a Member or customer of services provided by SPP. Directors may indirectly own securities through a mutual fund, and participation in a pension plan of a Member or customer is not deemed to be a direct financial benefit, so long as the performance of the Member or customer has no material effect on the pension plan. *Id.* at § 4.2.3. <u>Board Meetings</u> – The Board of Directors meets at least three times each year, Such meetings shall include the Members Committee and a representative from the Regional State Committee (described below). The Bylaws note that "failure of representatives of the Members Committee and/or of the Regional State Committee to attend, in whole or in part, shall not prevent the Board of Directors from convening and conducting business, and taking binding votes. Five Directors constitutes a quorum. Decisions are rendered by a simple majority vote of the Directors present and voting. No votes by proxy are permitted. *Id.* at §§ 4.6.1 and 4.6.3; *see also* October 1, 2004 Order on Compliance Filing, *Southwest Power Pool, Inc.*, 109 FERC ¶ 61,009 at P 23-25 (2004) (noting the revisions made by SPP to respond to the Commission's concerns regarding undue stakeholder influence over the Board.) <u>Committee Structure/Stakeholders</u> – SPP's governance structure includes several committees: *Members Committee*: The Members Committee consists of up to 18 persons

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		representing stakeholders; four from investor-owned utility Members, four from cooperative Members, two from municipal Members (including municipal joint action agencies), three from independent power producers/marketers Members, one from a state/federal power agency Member, and two from alternative power/public interest Members. Revised Bylaws at section 5.1.1.1. *Also see SPP*, 109 FERC 61,009 (2004). The Members Committee is charged with working with the Board of Directors to "manage and direct the general business of SPP." Specifically, the Members Committee provides individual and collective input to the Board of Directors, and may participate in straw votes to indicate the level of consensus among Members concerning actions pending before the Board. *Id.* § 5.1. In *Southwest Power Pool, Inc.*, 109 FERC ¶ 61,009 (2004), the Commission accepted SPP's revised composition of the Members Committee, noting that it properly added two seats for retail customers. The Commission directed SPP, however, to revise the Bylaws to define and distinguish between large and small retail customers, consistent with the *WestConnect* order, *Arizona Public Service Co.*, *et al.*, 101 FERC ¶ 61,033 (2002). *Markets and Operations Policy Committee*: Each Member of SPP appoints a representative to this committee, which reports to the Board of Directors and is charged generally with recommending system design, transmission and resource adequacy practices, coordinating efforts with NERC, reviewing and recommending operating plans, and reviewing, recommending and developing inter- and intraregional plans. *See* Revised Bylaws at § 6.1 (listing specific responsibilities of the committee.) *Strategic Planning Committee*: This 11-member committee reports to the Board of Directors, and is generally responsible for assessing the performance of SPP, establishing the organization's goals and vision, and reviewing its structure and recommending changes when necessary. The representatives on the committee include two Directors, the President, and four each from the Transmission Owners and Transmission Users sectors. *See id.* at § 6.2 (listing specific responsibilities of the committee.) *Human Resources Committee*: This committee also reports to the Board of Directors and is responsible generally for employment matters. *See id.* at § 6.3 (listing specific responsibilities of the committee.) *Compliance Committee*: This committee is made up of three Directors, and monitors

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		compliance with SPP and NERC policies, and recommends changes necessary for enforcement. *See id.* at § 6.4 (listing specific responsibilities of the committee.) *Finance Committee*: Also reporting to the Board of Directors, this committee is responsible for overseeing SPP finances and compliance with financially based legal and regulatory requirements. *See id.* at § 6.5 (listing specific responsibilities of the committee.) *Corporate Governance Committee*: This committee also reports to the Board of Directors, and is responsible generally for coordinating the filling of vacancies on the Board of Directors and other issues related to the Board's structure and functioning. *See id.* at § 6.6 (listing specific responsibilities of the committee.) There are nine seats on the committee, and the members of the committee include: the President of SPP, the Chairman or Vice-Chairman of the Board, one representative each selected by investor-owned utility Members, cooperative Members, municipal Members, independent power producers/marketers Members, state/federal power agencies Members, alternative power/public interest Members, and large/small retail Members. In *Southwest Power Pool, Inc.*, 109 FERC ¶ 61,009 at P 22 (2004), the Commission accepted the revised structure of the Corporate Governance Committee, but required that it revise the Bylaws to make the definition of large and small retail customers apply to section 6.6. <u>Regional State Committee</u> – The governance structure of SPP also includes a Regional State Committee (RSC), which is comprised of one designated commissioner from each state regulatory commission having jurisdiction over a Member of SPP. The RSC provides "direction and input on all matters pertinent to the participation of the Members in SPP." The RSC also has primary responsibility for determining regional proposals and the transition process in four areas: (1) whether and to what extent participant funding will be used to fund transmission expansions, (2) whether the regional access charge will be a license plate or postage stamp rate, (3) the allocation of Financial Transmission Rights, where a location price methodology is used, and (4) determining the transition mechanism to be used assure that existing firm customers receive Financial Transmission Rights equivalent to their existing firm rights. Additionally, the RSC is charged with determining the approach to resource adequacy across the SPP region, and with determining whether transmission upgrades for remote resources will be included in the regional transmission planning process and the role of transmission owners in proposing transmission upgrades in the regional planning process. SPP files any methodologies which the RSC reaches a decision on under

Organization	Summary	Research
		section 205 of the Federal Power Act (FPA), although SPP may also file its own related proposals. *See* Revised Bylaws at § 7.2; *see also Southwest Power Pool, Inc.*, 109 FERC ¶ 61,010 at P 94 (2004) (noting that the RSC has primary, but not sole responsibility with regard to the areas listed above, since SPP may also file its own proposals.)

Section 205 Filing Rights
Issue # 2

Organization	Summary	Research
CAISO	CAISO retains FPA section 205 rights. Market Participants retain section 206 rights.	CAISO's Tariff states that any amendment or other modification of the CAISO Tariff must be approved by the CAISO Governing Board in accordance with the CAISO bylaws. CAISO Tariff § 19. CAISO retains the right to unilaterally make an application to the Commission for a change in rates, terms, conditions, charges, classifications of service, Scheduling Coordinator (SC) Agreement (SC Agreement), rule or regulation under FPA section 205. Nothing contained in the CAISO Tariff or any SC Agreement will affect the ability of any Market Participant receiving service under the Tariff to exercise its rights under section 206 of the FPA and the Commission's rules and regulations. CAISO Tariff § 19.
MISO	Midwest ISO participants may make FPA section 205 filings, with certain restrictions applicable to ISO agreement signatories. ITCs are authorized to make unilateral applications for changes to rate schedules. Under the interconnection and operating agreement, parties may only file under section 205 in the event of material adverse changes in law or regulations. Midwest ISO may file under section 205 to impose mitigation measures againstparties exhibiting anticompetitive conduct that does not have a significant effect on market prices.	Nothing in the Midwest ISO Tariff, or in any service agreements, affects the rights of transmission provider, ITC, ITC participant or transmission owner to make filings under section 205 of the FPA, provided, however, transmission providers and transmission owners are restricted in their ability to make certain changes as detailed in the ISO Agreement. ITCs, and not transmission providers, are authorized to make unilateral applications for changes to rate schedules. Midwest ISO FERC Electric Tariff, Second Revised Volume No. 1, First Revised Sheet No. 48, effective December 23, 2002). Control Area Operators reserve the right under FPA section 205 to establish greater purchase obligations for load within the control areas. Midwest ISO FERC Electric Tariff, Second Revised Volume No. 1, First Revised Sheet Nos. 156, Original Sheet No. 156A, effective January 1, 2003, Original Sheets No. 157 and 158, effective April 1, 2002. Under the interconnection and operating agreement, parties may not unilaterally amend the agreement, except the parties may unilaterally file under FPA section 205 to modify the agreement in the event of material adverse changes in law or regulations that may adversely affect a party's rights and/or obligations, or may reasonably be expected to adversely affect a party's rights and/or obligations. Midwest ISO FERC Electric Tariff, Second Revised Volume No. 1, First Revised Sheet Nos. 156, First Revised Sheet No. 598, effective Dec. 23, 2002. Midwest ISO also may file under FPA section 205 to impose mitigation measures against parties exhibiting conduct that significantly departs from the conduct that would be expected under competitive market conditions if that conduct does not exceed other

Organization	Summary	Research
		more stringent measures described in the Tariff, but does have a significant effect on market prices or guarantee payments. Midwest ISO FERC Electric Tariff, Second Revised Volume No. 1, Original Sheet No. 619Q, effective Feb. 17, 2002; *see also Midwest ISO, et al.*, 105 FERC ¶ 61,212 (2003) (The Commission declined to fix a transitional lost revenue recovery mechanism to replace the eliminated regional through and out rates of transmission owners in Midwest ISO, and rejected previous guidance which invited parties to file for recovery under Section 205 of the FPA, instead having that authority reside solely with Midwest ISO); Letter Order issued August 13, 2003 (The Commission accepted revisions to Midwest ISO Tariff in Docket No. ER02-108-004, *et al.*, which eliminated the right of individual Transmission Owners to veto pricing structure within Midwest ISO*); Atlantic City Electric Co. et al. v. FERC*, 295 F.3d 1 (D.C. Cir. 2002), *on remand*, 101 FERC ¶ 61,318, *on appeal*, 329 F.3d 856 (2003) (The Commission has no statutory authority to order utilities to cede their statutory rights under section 205 of the FPA to file changes in rate design).
NYISO	NYISO and TOs have ability to file changes with the Commission.	Pursuant to section 9 of NYISO's OATT, the ISO and any Transmission Owner, with respect to a change in its revenue requirement, may make a unilateral filing for a change in rates terms and conditions, charges, classification of service, a Service Agreement, or a Network Operating Agreement. Section 9 of the OATT also states that nothing in the OATT shall be construed as affecting the ability of any party receiving service under this OATT to exercise its rights under the FPA. Finally, section 9A of the OATT states that the tariff may be modified only if both the ISO Board and the ISO Management Committee agree to such an amendment.
ISO-NE	Participants have full section 205 filing rights. ISO-NE has full section 205 filing rights.	Nothing contained in the Tariff or any Service Agreement affects in any way the right Participants or the ISO to file with the Commission under section 205 of the FPA and pursuant to the Commission's rules and regulations, for a change in any rates, terms and conditions, charges, classification of service, Service Agreement, rule or regulation. *See* NEPOOL Tariff, section 9; *see also* ISO-NE Tariff, Section 4.
PJM	Transmission Owners retain FPA section 205 rights for changes to non-rate terms, and conditions. The Board can petition the Commission	Transmission Owners may file changes to non-rate terms and conditions under FPA section 205 if the proposed changes are not rejected by a majority of the Board, and any such rejected changes may be filed under section 206. OA 7.7(vii). The Board reviews Transmission Owners' section 205 filings. OA 7.7(vii), First

Organization	Summary	Research
	to modify any provision of the OA or any Schedule or practice that the Board believes to be unjust, unreasonable, or unduly discriminatory.	Revised Sheet No. 33. Members, acting pursuant to a vote of the Members Committee (OA 8.4), can unilaterally make an FPA section 205 filing. OA 11.5(b). Arbitral decisions issued pursuant to dispute resolution procedures that affects matters subject to the Commission jurisdiction under section 205 shall be filed with FERC. OA, Schedule 5, 4.12. *See PJM Interconnection, LLC, et al.*, 101 FERC ¶ 61,345, P 38 n.31 (2002). PJM is a public utility in its own right because it operates jurisdictional facilities and therefore has the right to make its own section 205 filings. Furthermore, the Commission has approved a voluntary agreement between PJM and the PJM Transmission Owners allocating their respective 205 filing rights such that PJM's transmission owners are responsible for rate-related filings and PJM itself is responsible for terms and conditions-related filings. OA, 9.1-9.4. See also PJM Interconnection, LLC, 103 FERC ¶ 61170 (2003); *PJM Interconnection, L.L.C., et al.*, 105 FERC ¶ 61,294 (2003), *reh'g denied*, *PJM Interconnection, L.L.C.*, 108 FERC ¶ 61,032 (2004) (approving settlement between PJM and PJM East Transmission Owners); PJM Interconnection, L.L.C. and Virginia Electric and Power Company, 109 FERC ¶ 61,012 (2004) (205 filing rights for PJM South Transmission Owners); *PJM Interconnection, L.L.C. et al.*, 108 FERC ¶ 61,318 (2004) (205 filing rights for PJM West Transmission Owners).
SPP	SPP is permitted to make section 205 filings on behalf of its Members, to propose pricing for transmission service or to propose changes in prices, terms and conditions of service, "as is necessary to fulfill its obligations" under the Membership Agreement. Transmission Owners possess the unilateral right to make section 205 filings to change rates or rate structure for transmission service over their own Tariff facilities, and submit proposals or filings governing new construction. Transmission Owners may not make a section 205 filing which will result in a transmission customer paying two or	The section 205 filing rights of SPP are confirmed in several sections of the governing documents. The Revised Membership Agreement states that SPP is responsible for proposing and filing with the Commission, pursuant to section 205, modifications to the SPP OATT, including rate design. *See* Revised Membership Agreement at § 2.1.1(h). Additionally, the Revised Bylaws provide that one of the duties of the Board of Directors is to "authorize filings with regulatory bodies." Revised Bylaws at § 4.1(n). The Revised Membership Agreement contains two specific provisions regarding section 205 filing rights. First, section 2.2.1 provides: > [SPP] on behalf of its Members may propose to FERC such transmission pricing for transmission service as is necessary to fulfill its obligations under this agreement, and may propose to FERC such changes in prices, pricing methods, terms, and conditions as are necessary to continue to fulfill such obligations. Section 3.10 states:

Organization	Summary	Research
	more transmission charges for one transaction under the SPP OATT.	Transmission Owner shall possess the unilateral right to file with FERC pursuant to Section 205 of the Federal Power Act modifications to change the rates or rate structure for transmission service over its Tariff Facilities and to submit proposals or filings governing new construction with FERC; provided, however, Transmission Owner may not submit a proposal which results in a Transmission Customer paying two or more transmission charges for transmission for one transaction under the OATT (excluding Distribution Facilities for which an additional charge may be imposed, and Grandfathered Agreements as defined in the OATT). Pursuant to *Southwest Power Pool, Inc.*, 106 FERC ¶ 61,110, at P 98 (2004), "SPP may make any Section 205 filing it deems appropriate while the TOs have specific Section 205 filing rights."

Exit Rights
Issue # 3

Organization	Summary	Research
CAISO	Termination rights are found in the CAISO Tariff and SC Agreements. The CAISO Tariff "shall terminate upon approval of termination by the ISO Governing Board. A SC's SC Agreement may be terminated by CAISO on written notice to the SC.	Several provisions of the CAISO Tariff contain termination rights. CAISO Tariff - The CAISO Tariff "shall terminate upon approval of termination by the ISO Governing Board in accordance with the bylaws of the ISO and receipt of any necessary regulatory approval from FERC." CAISO Tariff § 18.2. SC Agreement - Energy and Ancillary Services may be transmitted on behalf of an Eligible Customer into, out of or through the CAISO Controlled Grid, only if scheduled by a SC. CAISO Tariff § 2.1.1. A SC's SC Agreement may be terminated by CAISO on written notice to the SC. A SC may terminate a SC Agreement on sixty (60) days written notice to CAISO, provided such notice will not be effective to terminate the SC Agreement until the SC has complied with the requirements of section 2.2.5 (Eligible Customers Represented by Scheduling Coordinators). CAISO Tariff § 2.2.4.5 (b).
NYISO	Any transmission customer may withdraw from the OATT on 30 days prior written notice to NYISO.	Pursuant to section 1A.2 of NYISO's OATT *any* transmission customer may withdraw from the OATT on thirty (30) days prior written notice to NYISO.
ISO-NE	Participants can exit no less than six months after giving prior notice. Section 203 approval is not required to exit. Participants' Committee may terminate a bankrupted Participant's status. NEPOOL may initiate a proceeding to terminate a Participant's status that fails to fulfill Tariff obligations. Terminated Participants' facilities can still be operated by NEPOOL for reliability reasons.	Any Participant has the right to terminate its status as a Participant upon no less than six months' prior written notice given to the Secretary of the Participants Committee. Restated NEPOOL Agreement, section 21.2(a), Sheet No. 262. Participants are not required to seek section 203 approval as a condition to its withdrawal from ISO-NE. *See Atlantic City Electric Company, et al. v. FERC*, 295 F.3d 1 (D.C. Cir. 2002). The Participants Committee may terminate a Participant's status as a Participant if that Participant: (i) a receiver or trustee of a Participant is appointed; or (ii) a Participant is adjudicated bankrupt or an order for relief is entered under the Federal Bankruptcy Code against a Participant; or (iii) there is filed against any Participant in any court a petition in bankruptcy or insolvency or for reorganization or for appointment of a receiver or trustee of all or a portion of the Participant's property, and within ninety (90) days after the filing of such a petition against the Participant, the Participant shall fail to secure a discharge thereof; or (iv) any Participant shall file a petition in voluntary bankruptcy or seeking relief under any provision of any bankruptcy or insolvency law or shall make an assignment for the benefit of creditors. Restated NEPOOL

Organization	Summary	Research
		Agreement, section 21.2(b), Sheet No. 263. If a Participant fails to pay all amounts invoiced to it by NEPOOL, or the Participant otherwise fails to comply with the Billing Policy or the Member Financial Assurance Policy, or the Participant fails to perform any other obligation under the Tariff, and such failures continues for at least five (5) days in the case of a Payment Default, or ten (10) days in all other defaults, NEPOOL may notify such Participant in writing that it is in default, and NEPOOL may initiate a proceeding before the Commission to terminate such Participant's status as a Participant. NEPOOL must also notify each member on the Participants Committee and each Participant's billing contact to the identity of the Participant, the nature of the default, and the actions NEPOOL plans to take. Pending Commission action on such termination, NEPOOL may suspend service to the Participant on or after fifty (50) days after the giving of such notice. The Participant is responsible for all costs and fees associated with the proceedings to terminate such Participant. Restated NEPOOL Agreement, section 21.2(d), Sheet Nos. 264-264B. If the status of a Participant is terminated, such Participant's generation and transmission facilities shall continue to be subject to such NEPOOL or other requirements relating to reliability as the Commission may approve, for so long as the Commission may direct. Further, any such Participant's transmission facilities that are required in order to permit transactions among any of the remaining Participants, all pending requests for transmission service under the Tariff relating to such Participant's facilities shall be followed to completion and all existing service over the facilities shall be provided for a period of three years. Restated NEPOOL Agreement, section 21.2(e), Sheet No. 265.
PJM	Withdrawal and termination rights and requirements are contained in the Operating Agreement and the Transmission Owners Agreement.	The withdrawal or termination of any member is subject to OA 18.18, must be filed with the Commission, and is effective only upon the Commission's approval. OA, 4.1(b)-(c). The duty to indemnify continues despite withdrawal. OA, 16.1(a). A member may withdraw, subject to the requirements of OA, 4.1(c) & Schedule 1, 1.4.6, provided that 90 days notice is given to the Office of the Interconnection. OA, 18.18. A PJM Transmission Owner seeking to withdraw from PJM does not need to obtain prior Commission approval under section 203, but they must make a section 205 filing before they withdraw. PJM Transmission Owners Agreement, 3.2; PJM West Transmission Owners Agreement, 3.2. *See also PJM Interconnection, LLC*, 105 FERC ¶ 61,294 (2003), *reh'g denied*, 108 FERC ¶ 61,032 (2004) (PJM East Transmission Owners); *PJM Interconnection, L.L.C. et al.*, 108 FERC ¶ 61,318 (2004) (PJM West Transmission Owners).

Organization	Summary	Research
		An Internal Market Buyer that is a Load Serving Entity may withdraw by giving notice that specifies an effective date, which is not earlier than the effective date of its withdrawal from the Reliability Assurance Agreement or its assumption of obligations under the Reliability Assurance Agreement. OA, Schedule 1, 1.4.6(a). An External Market Buyer or Internal Market Buyer that is not a Load Serving Entity may withdraw by giving notice and specifying an effective date at least one day after the notice. OA, Schedule 1, 1.4.6(b). Withdrawal does not relieve a Market Buyer of any obligation to pay for electric energy, for fees and charges, or for indemnification (costs) that the Market Buyer incurred prior to withdrawal. OA, Schedule 1, 1.4.6(c). A Market Seller may withdraw by giving written notice to OI specifying an effective date of withdrawal at least one day after the date of the notice; however, the withdrawal will not relieve a Market Seller of any obligation to deliver electric energy or related services to PJM Interchange Energy Market or pay its share of any fees and charges incurred or assessed prior to the date of such withdrawal. A Market Seller that has withdrawn form the OA may reapply to become a Market Seller at any time, provided that it is not in default with respect to any obligation incurred under the OA. OA, 1.5.2 (a) and (b). The Office of the Interconnection is responsible for evaluating the effect of withdrawal (or removal) of a party from the Reliability Assurance Agreement. OA, Schedule 8, 2(b). Withdrawal does not relieve a Market Participant of any obligation to furnish or pay for Capacity Credits, for fees and charges, or for indemnification (costs) that the Market Participant incurred prior to withdrawal. OA, Schedule 11, 3.2.
SPP	A Transmission Owner may withdraw from SPP upon 12 months notice. The withdrawal of a Transmission Owner does not become effective until the Commission accepts the notice of withdrawal or otherwise allows the withdrawal. The withdrawal of a Transmission Owner is generally made subject to	Section 4.0 of the Revised Membership Agreement sets forth the general procedures for the withdrawal of a Member from SPP. Both Transmission Owners and Non-Transmission Owners must give twelve months written notice to SPP in order to withdraw. Transmission Owners under the Commission's jurisdiction must additionally have their withdrawal accepted by the Commission. Revised Membership Agreement at §§ 4.1.1 and 4.2.4. Additionally, if the withdrawal of a Transmission Owner will create a situation in which another Transmission Owner will become physically disconnected from the SPP region, SPP will determine the ability of the other Transmission Owner to continue its membership. *Id*. The Revised Membership Agreement also clarifies that withdrawing members remain

Organization	Summary	Research
	Federal and State law and any necessary regulatory approvals. A Non-Transmission Owner may withdraw upon 12 months notice. Members withdrawing from SPP are required to pay all existing obligations, which include membership fees, assessments, and the member's share of other expenses.	responsible for "existing obligations," which are detailed in section 4.2.2. In its Order Granting RTO Status Subject to Fulfillment of Requirements, *Southwest Power Pool, Inc.*, 106 FERC ¶ 61,110 (2004), the Commission found the withdrawal requirements "just and reasonable and in accordance with our guidance." RTO Order at P 66. The Commission noted that the Revised Membership Agreement "provides that no public utility may withdraw without an affirmative finding by this Commission and a finding that such withdrawal is just and reasonable." *Id*. On rehearing, the Commission stated that the requirement for Commission approval is not conditioned on any other section of the Agreement, including section 5.1.b. The Commission construed that section to apply to circumstances where "'regulatory and other approvals or acceptances are not obtained or changes are required' with respect to the initial effectiveness of the agreement." *Southwest Power Pool, Inc.*, 109 FERC ¶ 61,010 at P 22 (2004).

Market Monitoring Units (MMU's)
Issue # 4

Organization	Summary	Research
CAISO	The Department of Market Analysis (DMA) is accountable to the CAISO CEO, through the CAISO Chief Legal Counsel, on all matters affecting the effectiveness and integrity of the CAISO Market. The DMA also prepares reports to the Commission and other regulatory agencies, which will be reviewed and approved by the CAISO CEO and Governing Board, and then submitted as required.	<u>Internal DMA vs. consultant DMA</u> - Currently, market monitoring activities are carried out internally by full-time CAISO staff. MMIP 3.2. <u>DMA independence from market players</u> - The DMA is comprised of full-time CAISO staff, MMIP 3.2., which cannot contract to work for public utilities and may not hold public utility securities. *See* CAISO Employee Code of Conduct. <u>Accountability of DMA to the Commission or to RTO/ISO Board?</u> - As required in the CAISO Tariff or by the CAISO CEO and CAISO Governing Board, or as required by the regulatory agency with jurisdiction over the matters in question, the DMA shall prepare reports to the FERC and other regulatory agencies, which will be reviewed and approved by the CAISO CEO and Governing Board and then submitted as required. MMIP 4.4.2. The DMA reports and is accountable to the CAISO CEO through the CAISO Chief Legal Counsel, on all matters concerning policy and other matters that may affect the effectiveness and integrity of the monitoring function. The "other matters" include: market monitoring; information development and dissemination pertaining to generic or entity-specific investigations, and corrective actions or enforcement. MMIP 3.3.1. The DMA is directed by a Compliance Director who is under the management of the CAISO Chief Legal Counsel and the CAISO CEO. MMIP 3.2.
MMU Responsibilities and Authority	The DMA is authorized to monitor for the abuse of Reliability Must-Run (RMR) Units and market structure flaws. Where the monitoring activities reveal a significant possibility of the presence of or potential for the exercise of market power, the DMA will refer the matter to the Commission for enforcement. Where the monitoring activities reveal that activities or behavior of market	The DMA is authorized to monitor activities that affect the operation of CAISO markets. Among other things, CAISO monitors: abuse of RMR Units and market structure flaws. MMIP 2.1.1 – 2.1.2. *See also* MMIP 4.1.1. Where the monitoring activities or any consequent investigations carried out by the DMA reveal a significant possibility of the presence of or potential for the exercise of market power that would adversely affect the operation of CAISO markets, the DMA shall refer this matter to the Commission for action. *See* 107 FERC ¶ 61,118. Where the monitoring activities or any consequent investigations carried out by the DMA pursuant to MMIP 2.1 and 2.2 reveal that activities or behavior of market participants have the effect, or potential for, undermining the efficiency, workability or reliability of CAISO market, or to give the market participant an unfair competitive

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	participants have the effect, or potential for, undermining the efficiency, workability or reliability of CAISO market, or to give the market participant an unfair competitive advantage over other market participants, the DMA will refer the matter to the Commission. Where ordered by the regulatory or antitrust agency with jurisdiction over the matter, or by a court of competent jurisdiction, the DMA will refer a matter through the CAISO CEO to the agency concerned. CAISO's proposed Amendment No. 55 (behavioral rules) was conditionally accepted by the Commission, subject to modifications. The compliance filing is still under consideration.	advantage over other market participants, the DMA will refer the matter to the Commission pursuant to 107 FERC ¶ 61,118, which says that until the governing board is deemed independent the Commission shall conduct all investigating and enforcement functions for CAISO. <u>CAISO Amendment No. 55 (Docket No. ER03-1102-000)</u> - On February 20, 2004, the Commission directed CAISO to modify the behavioral rules proposed in Amendment No. 55 to be consistent with the Commission's behavioral rules order in Docket Nos. EL01-118-000 and EL01-118-001.[2] Subject to the Commission's acceptance of a CAISO filing that demonstrates that the CAISO has established an independent Governing Board in compliance with the Commission's orders in Docket No. EL01-35-000, et al.,[3] the Commission accepted CAISO's proposal to charge pre-defined penalties for certain objectively identifiable behaviors, and directed modification of Amendment No. 55 to conform it to the Commission's MBR Tariff Order,[4] and otherwise provide direction to the CAISO. On May 6, 2004, the Commission issued an order on rehearing in this matter. Then on May 20, 2004, CAISO filed its compliance filing, which is still under consideration. This order represents the first application of the Commission's recently adopted behavioral rules and benefits customers in the CAISO markets by providing a reasonable approach to investigating and sanctioning anticompetitive behavior.
Market Power Mitigation	CAISO's market power mitigation measures are intended to mitigate the market effects of any conduct that would substantially distort competitive outcomes in the Real-Time Market while avoiding unnecessary interference with competitive price signals.	CAISO Tariff § 2.1 contains the practices subject to the DMA's scrutiny. *See also* Market Mitigation Plan contained in MMIP, Appendix A. The market power mitigation measures are intended to provide the means by which CAISO may mitigate the market effects of any conduct that would substantially distort competitive outcomes in the CAISO Real -Time Market while avoiding unnecessary interference with competitive price signals. Appendix A, section 1.1. CAISO also monitors for conduct it determines constitutes an abuse of market power, but does not trigger the thresholds specified for imposition of mitigation measures. Appendix A, section 1.2.
MMU Relationship to State Commissions	The Commission allowed the State, acting through EOB, a level of review	The Commission previously allowed the State, acting through EOB, a level of review authority over CAISO, but only with regard to matters that were not subject to

[2] *Investigation of Terms and Conditions of Public Utility Market-Based Rate Authorizations*, 105 FERC ¶ 61,218 (2003) (*MBR Tariff Order*).
[3] *Mirant Delta, LLC, et al. v. California Independent System Operator, Corp.*, 100 FERC ¶ 61,059 (2002) (*Mirant*), *reh'g granted in part and denied in part*, 100 FERC ¶ 61,271, *reh'g denied*, 101 FERC ¶ 61,078 (2002).
[4] *See supra* n. 1.

Organization	Summary	Research
	authority over CAISO, but only with regard to matters that were not subject to exclusive federal jurisdiction.	exclusive federal jurisdiction. The Commission allowed EOB confirmation power over only those members of the Board representing end users and public interest groups and review power over only those CAISO decisions concerning certain state-retail matters. *See California Electricity Oversight Board*, 88 FERC ¶ 61,172, *reh'g denied*, 89 FERC ¶ 61,134 (1999), *appeal dismissed sub. nom., Western Power Trading Forum v. FERC*, 245 F.3d 798 (D.C. Cir. 2001). In doing so, the Commission stated, EOB may not review or dictate the rates, terms, and conditions of transmission in interstate commerce and may not require the CAISO to make filings with the Commission, dictate the content of such filings, or limit the right of the ISO to make such filings at the Commission. *Id.* at 61,577-578.
Information Sharing by MMUs: What is Permitted?	If CAISO is required to disclose confidential information, it may provide such information, provided CAISO's notifies any affected market participant as soon as CAISO learns of the disclosure requirement.	Under CAISO Tariff § 20.3.4(b), if CAISO is required by applicable laws, regulations, or in the course of administrative or judicial proceedings, to disclose information otherwise required to be confidential under the CAISO Tariff, CAISO may provide such information, provided that as soon as CAISO learns of the disclosure requirement and prior to making such disclosure, CAISO shall notify any affected market participant of the requirement.
MISO **MMUs** **MMU Independence**	Midwest ISO retains an external independent market monitor (IMM). The IMM may not have equity or other financial interest in a Midwest ISO market participant. The IMM may not undertake a matter on behalf of an interested party. The IMM reports to the Midwest ISO Board of Directors, and reports findings annually to the Commission and State regulatory agencies. The Midwest ISO's monitoring and mitigation plan is set out in Module D of the TEMT.	<u>The Midwest ISO's market monitoring and mitigation plan</u> is set out in Module D of the TEMT filed on March 30, 2004. <u>Internal MMU vs. consultant MMU</u> - Midwest ISO retains Potomac Economics (David Patton) as the Independent Market Monitor (IMM). <u>MMU independence from market players</u> - Midwest ISO FERC Electric Tariff, Second Revised Volume No. 1, First Revised Sheet No. 610A, effective July 1, 2002. IMM may not have equity or other financial interest in a Midwest ISO market participant, its parent, subsidiary, or affiliate. Moreover, IMM may not undertake a matter for or on behalf of an interested party involving the structure, performance or rules, standards or procedures of the Midwest ISO market. IMM may undertake matters not related to the above issues as long as such involvement is disclosed to the Midwest ISO Market Monitoring Liaison Officer and he/she determines such involvement will not compromise the independence or integrity of the IMM. Midwest ISO FERC Electric Tariff, Second Revised Volume No. 1, Original Sheet No. 619C.01 (Exhibit A to Attachment S-1, Independent Market Monitor Conflicts Policy), effective December 23, 2002.

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		<u>Accountability of MMU to the Commission and/or RTO/ISO Board</u> - IMM reports to the Midwest ISO Board of Directors, and reports its findings annually to the Commission, state regulatory agencies and Midwest ISO. Midwest ISO FERC Electric Tariff, Second Revised Volume No. 1, First Revised Sheet No. 607, effective July 1, 2002.
MMU Responsibilities and Authority	The MMU assists with the development and implements the market monitoring plan. The MMU does not monitor bilateral energy or capacity markets or private transmission rights. The IMM recommends modifications to market rules, tariffs and other corrective action to improve competitiveness or efficiency. The IMM shares with the Commission information provided to states pursuant to state requests. The Commission partially accepted the IMM market monitoring plan, retention agreement and market mitigation measures, but rejected subsequent compliance filings. The IMM may suggest that Midwest ISO make a filing under section 205 requesting authorization to include specific anti-competitive conduct that does not trigger mitigation within the types of conduct for which mitigation measures may be imposed. No entity may screen, alter, delete or	IMM assists with the development, and subsequently implements, the market monitoring plan (Plan), which covers the imbalance energy market, any congestion management market or system, any ancillary services market, any market for the purchase and sale of transmission rights, and any other market administered, coordinated or facilitated by Midwest ISO. The IMM will not monitor bilateral energy or capacity markets, or private transmission rights not administered, coordinated or facilitated by Midwest ISO, except to periodically assess the effect of these markets on the Midwest ISO's markets and services and vice versa. IMM recommends modifications to market rules, tariffs, or other corrective action to improve competitiveness or efficiency. Midwest ISO FERC Electric Tariff, Second Revised Volume No. 1, First Revised Sheet No. 607, 608, effective July 1, 2002. The IMM will also monitor the markets and services administered by the Midwest ISO for any conduct that may distort competitive outcomes, but that does not trigger the thresholds specified for the imposition of mitigation measures. (This issue is currently on rehearing.) The IMM monitors schedules and bids submitted for and actual dispatch of generating units (to identify physical and economic withholding, as well as uneconomic production, load bidding or virtual bidding), the provision of transmission services by Midwest ISO, including estimates and postings of available transfer capability, tariff administration, operation and maintenance of the transmission system, auctions and other markets for transmission rights, reservation and scheduling. The IMM also looks into the nature, extent, causes and costs of, and charges for congestion. Midwest ISO FERC Electric Tariff, Second Revised Volume No. 1, Original Sheets No. 619E through 619J, effective Feb. 17, 2002. Upon request for data or information from a state, the IMM must simultaneously share that information with the Commission. Midwest ISO FERC Electric Tariff, Second Revised Volume No. 1, Second Revised Sheet No. 614. *See also Midwest ISO*, 99 FERC ¶ 61,237 (2002) (The Commission directed Midwest ISO to submit a revised Retention Agreement and to modify the Market Monitoring Plan in a compliance

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	delay IMM investigations. The IMM may not impose sanctions, penalties or fines, but it may impose mitigation measures. The IMM reports findings, annual reports, and results of investigations, when warranted, to state regulatory agencies. The IMM may at any time bring a matter to the attention of state (as well as federal) antitrust enforcement authorities as deemed necessary to implement the Market Monitoring Plan.	filing); *Midwest ISO*, 101 FERC ¶ 61,228 (2002) (The Commission conditionally accepted Midwest ISO Market Monitoring Plan and Retention Agreement as Attachments S and S-1, respectively, to the Midwest ISO Open Access Transmission Tariff); *Midwest ISO*, 102 FERC ¶ 61,280 (2003) (The Commission accepted, subject to modification, the proposed Market Mitigation Measures as Attachment S-2 to the Midwest ISO OATT). *Midwest ISO*, 105 FERC ¶ 61,146 (2003) (The Commission rejected compliance filings in light of Midwest ISO's request and the Commission's approval of the withdrawal of a proposed Transmission and Energy Markets Tariff, which was to include a module on Market Mitigation Measures).[5] If the IMM discovers conduct that may distort competitive market outcomes, but that conduct does not trigger thresholds for the imposition of market mitigation measures, Midwest ISO must make a filing under FPA section 205 requesting authorization to apply appropriate mitigation measures. Midwest ISO FERC Electric Tariff, Second Revised Volume No. 1, Original Sheet No. 619E, effective February 17, 2002). No entity, including Midwest ISO and state regulatory agencies, may be granted authority to screen, alter, delete or delay IMM investigations or the preparation of findings, conclusions and recommendations developed by IMM that fall within the scope of its market monitoring responsibilities. Midwest ISO FERC Electric Tariff, Second Revised Volume No. 1, First Revised Sheet No. 608. IMM shall <u>not</u> have the authority to impose sanctions, penalties or fines. Midwest ISO FERC Electric Tariff, Second Revised Volume No. 1, First Revised Sheet No. 611, effective July 1, 2002. Midwest ISO is authorized to impose financial penalties if the IMM determines that conduct of participants has led to a substantial increase in one or more prices or guarantee payments in the Midwest ISO market. Midwest ISO FERC Electric Tariff, Second Revised Volume No. 1, Original Sheet No. 619T, effective February 17, 2002.
Market Power Mitigation		The IMM may impose mitigation measures to remedy conduct that is significantly inconsistent with competitive conduct; and would result in a substantial change in one or more prices in a Midwest market or production cost guarantee payments to a market participant related to a binding transmission constraint, a local reliability constraint, or a market design flaw. Midwest ISO FERC Electric Tariff, Second Revised Volume No.

[5] Midwest ISO l filed a new tariff on March 31, 2004, with market launch anticipated on March 1, 2005.

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		1, Original Sheet No. 619H, effective February 17, 2002.
MMU's Relationship to State Commissions		The IMM reports findings, annual reports, and results of investigations, when warranted, to state regulatory agencies. The IMM also responds to state requests for additional information or additional analysis, or information it has in its possession, subject to confidentiality requirements. Midwest ISO FERC Electric Tariff, Second Revised Volume No. 1, First Revised Sheet No. 607, 608.
Information Sharing by MMUs: What is Permitted?		The IMM may at any time bring a matter to the attention of state (as well as federal) antitrust enforcement authorities as deemed necessary to implement the Market Monitoring Plan. Midwest ISO FERC Electric Tariff, Second Revised Volume No. 1, First Revised Sheet No. 611.
NYISO **MMUs** **MMU Independence**	NYISO's internal MMU is charged with ensuring fair access to the appropriate segment of the bulk electric power market for all market participants. NYISO also retains an external consultant known as the NYISO Market Advisor The NYISO Market Advisor advises the Board and prepares and submits reports on the nature and extent of the efficiency of the NY electric markets. The MMU acts at the direction of the CEO, who is accountable for the implementation of the Market Monitoring Plan Existing policy on conflicts of interest for the NYISO Market Advisor establishes appropriate standards for the professional and financial independence of the NYISO Market Advisor.	NYISO filed its Market Monitoring Plan with the Commission on July 26, 1999. It was accepted by the Commission on November 23, 1999. *See* 89 FERC ¶ 61,196 (1999). NYISO's Market Administration and Control Area Service Tariff, Attachment H contains the ISO's Market Power Mitigation Measures. NYISO's Market Monitoring Unit (MMU) is charged with ensuring fair access to the appropriate segment of the bulk electric power market for all market participants. The NYISO's Market Monitoring Plan provides the MMU with the authority to initiate investigations into market events, conduct, or performance, as required. Market participants, may also request that NYISO conduct a formal investigation relative to a specifically identified market issue. The MMU is staffed by full-time employees of the NYISO. In carrying out its responsibilities, the MMU may retain such consultants and other experts as it deems appropriate to the effective implementation of this Plan, subject to the management oversight of the CEO. The MMU also works with an outside consultant known as the NYISO Market Advisor (currently, Potomac Economics). The Market Advisor shall have the experience and expertise appropriate to the analysis of competitive conditions in markets for electric capacity, energy and ancillary services, and financial instruments such as TCCs, and to such other responsibilities as are assigned to it under the Market Monitoring Plan. The NYISO Market Advisor advises the Board and prepares and submits reports on the nature and extent of, and any impediments to, competition in and the economic efficiency of the NY electric markets. The Market Advisor may at any time bring any matter to the attention of the Board as it may deem necessary or appropriate for achieving the purposes, objectives and effective implementation of the Market Monitoring Plan. The Market Advisor should not have any conflicts of interest with the NYISO that would compromise its professional and financial independence.

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		<u>Accountability</u> - The MMU acts at the direction of the CEO, who is accountable for the implementation of the Market Monitoring Plan. The NYISO Market Advisor is also accountable to the CEO and serves at the pleasure of the Board. The MMU and Market Advisor will prepare an annual report on the competitive structure and performance of, and the economic efficiency of the NY electric markets. A copy of this report will be provided to the Commission and other interested state agencies. Additionally, the Commission (and other interested government agencies) may request that the MMU or the Market Advisor prepare other reports on any matters within their purview. Pursuant to § 4.2 "Conflicts of Interest" of NYISO's Market Monitoring Plan, the Board shall adopt a policy on conflicts of interest for the NYISO Market Advisor establishing appropriate standards for the professional and financial independence of the NYISO Market Advisor.
MMU Responsibilities and Authority	If the MMU believes that a party has engaged in anti-competitive behavior, it will contact the party, identify the behavior, and request an explanation. If the conduct is judged to have had or likely to have material price effects in the market, one of three types of mitigation measures may be imposed Day-Ahead and Real-Time mitigation are both currently employed.	NYISO's market mitigation plan specifies that physical or economic withholding of an electric facility and uneconomic production from an electric facility are the types of conduct that may warrant mitigation. Various indices and screens will be developed and used to detect such market power behavior. Day-Ahead mitigation and Real-Time mitigation are currently employed by NYISO. If the MMU believes that a party has engaged in anti-competitive behavior, it will contact the party, identify the behavior, and request an explanation. No further action will be taken if the MMU, in consultation as appropriate with the Market Advisor, is satisfied with the party's explanation that the behavior was not an exercise of market power. However, if the conduct is judged to have had or likely to have material price effects in the market, one of three types of mitigation measures may be imposed. They are: bid restrictions; an obligation to pay for operating reserves; or a default bid. In real time, conduct and impact thresholds are used to trigger bid caps. NYISO may impose financial penalties as a result of abuse of market power as outlined in section 4 of Attachment H "Market Mitigation Measures" of NYISO's Market Administration and Control Area Services Tariff. *See generally* 89 FERC ¶ 61,196 (1999), 90 FERC ¶ 61,317 (2000), 95 FERC ¶ 61,471 (2001), and 96 FERC ¶ 61,249 (2001).
Market Power Mitigation		
MMU's Relationship to State Commissions	MMU and Market Advisor will provide the state commission with a copy of its annual report	The MMU and Market Advisor will provide the state commission with a copy of its annual report on the competitive structure and performance of, other competitive conditions in or affecting, and the economic efficiency of the New York Electric

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		Markets. The MMU and Market Advisor will also prepare other reports as may be requested by the state commission. *See* section 10 of NYISO's Market Monitoring Plan.
Information Sharing by MMUs: What is permitted?	The MMU, in consultation with the Market Advisor, shall make publicly available various types of information.	The MMU, in consultation with the Market Advisor, shall make publicly available: (i) a description of the categories of data and information collected and maintained by the MMU; (ii) such data or information as may be useful for the competitive or efficient functioning of any of the NY electric markets that can be made publicly available consistent with the confidentiality of Protected Information; and (iii) if and to the extent consistent with confidentiality requirements, such summaries, redactions, abstractions or other non-confidential compilations, versions or reports of Protected Information as may be useful for the competitive or efficient functioning of any of the NY electric markets. Any such proposed methods for creating non-confidential reports of such information shall only be adopted after provision of a reasonable opportunity for, and consideration of, the comments of Market Parties and other interested parties. All such proposed or adopted methods shall be set forth in the ISO Procedures, shall be made available through the ISO web site or comparable means, and shall be subject to review and approval by the Board.
ISO-NE **MMUs** **MMU Independence**	ISO-NE has an Independent Market Advisor and an internal monitoring unit. The IMA is independent of market players. ISO-NE publishes a quarterly report made available to the Commission.	<u>MMU</u> – ISO-NE and the Independent Market Advisor (IMA) monitor the NEPOOL market. NEPOOL Standard Market Design (SMD), Appendix A, section 1.2, Original Sheet No. 204. <u>MMU independence from market players</u> – The IMA, by definition, is independent of market players. NEPOOL SMD, Appendix A, section 1.2, Original Sheet No. 204. <u>Accountability of MMU to the Commission or to RTO/ISO Board</u> – ISO-NE will publish a quarterly report made available to appropriate state or federal government agencies, including the Commission and state regulatory bodies, attorneys general and others with proper jurisdiction. NEPOOL SMD, Appendix A, section 11.2.2, Original Sheet No 224.
MMU Responsibilities and Authority	MMU mitigates specific conduct that exceeds defined thresholds. Before mitigation, MMU must evaluate all evidence, including evidence presented by the Participant in question.	The MMU mitigates specific conduct that exceeds well-defined, Commission-accepted thresholds specified within the SMD. If the MMU finds that there has been an abuse in market power, but none of the threshold levels have been exceeded, ISO-NE must submit a section 205 filing that identifies the conduct that warrants mitigation, as well as a specific Mitigation Measure to remedy the conduct. NEPOOL SMD, Appendix A, Sections 1.1-1.2, Original Sheet No. 204.

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	ISO-NE may limit the hourly quantities of Decrement Bids and Increment Offers by a guilty Participant. MMU can mitigate based on Economic Withholding and Uneconomic Production. The mitigation measures remedy conduct that is inconsistent with competitive conduct and would result in a material change in prices.	The following conduct is subject to mitigation: Supply Offers; Increment Offers; Demand Bids; Decrement Bids; offers relating to ICAP; and the scheduling or operation of a generation unit or transmission facility. NEPOOL SMD, Appendix A, Section 2.1, Original Sheet 205. ISO-NE, before imposing mitigation for violation of general market thresholds, must first: (1) contact the Participant to request an explanation of the conduct; (2) evaluate the explanation – if the explanation is deemed sufficient as to convince ISO-NE that the conduct is consistent with competitive behavior, no further action is taken; and (3) ISO-NE must consider all information submitted, but is not required to delay mitigation while waiting for information. NEPOOL SMD, Appendix A, Section 3.1.1, Original Sheet No. 208. Mitigation measures for Increment Offers and Decrement Bids: ISO-NE may limit the hourly quantities of Increment Offers for supply or Decrement Bids for load that may be offered in a zone by a Participant whose bid and offer practices have been determined to contribute to an unwarranted divergence of LMPs between the Day-Ahead and Real-Time Energy Markets. The specific level of the limitation is to be determined in ISO-NE's best judgment. NEPOOL SMD, Appendix A, Section 8.2.2, Original Sheet No. 221-222. Mitigation measures of Economic Withholding and Uneconomic Production: The Default Offer may establish a mitigated value for one or more components of the offer for a given Resource equal to a Reference Level for that component of the Resource's offer. A Resource subject to a Default Offer shall be paid the LMP or other market clearing price applicable to the output from the Resource. Accordingly, a Default Offer shall not limit the price that a Resource may receive or pay unless the Default Offer determines the LMP or other market clearing price applicable to that Resource. Such measures shall not be applied if the price effects of the measures would cause the average day-ahead energy price in the mitigated locations to rise over the entire day. Mitigation shall be imposed from the first hour in which the impact test is met to the last hour in which the impact test is met, or for the duration of the mitigated Resource's minimum run time, whichever is longer. The posting of the Day-Ahead schedule, rebidding period and reliability commitment run may be delayed, if necessary. Mitigation that does not affect the LMP or a clearing price in another ISO market may be applied in the settlement process. If in a constrained area, the measures shall remain in effect for the duration of any day in which there is an interval for which such mitigation is deemed warranted. NEPOOL SMD, Appendix A, Section 5.7.4, Original Sheet No. 219-220. Mitigation of Physical Withholding - Both administrative and formula-based sanctions

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		may be imposed. See NEPOOL SMD, Appendix B, Exhibit 1, Original Sheet No. 323-324.
Market Power Mitigation		ISO-NE and IMA monitor the NEPOOL markets for any abuse of market power, even if it does not trigger one of the well-defined threshold levels. The mitigation measures remedy conduct that: (1) is significantly inconsistent with competitive conduct; and (2) would result in a material change in one or more prices in the NEPOOL Market or Operating Reserve payments to a Participant. Conduct will be considered inconsistent with competitive conduct if the conduct would not be in the economic interest of the Participant in the absence of the ability to affect market price. NEPOOL SMD, Appendix A, Section 2.2.1-2.2.2, Original Sheet No. 205.
MMU's Relationship to State Commissions	A Regional State Committee is not yet in place.	On June 25, 2004, the Governors of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont submitted a Joint Petition for Declaratory Order to form a New England Regional State Committee on Electricity. *See* Docket No. EL04-112-000. The Committee will focus on developing and making policy recommendations related to resource adequacy and systems planning, and investigating and reporting to the New England Governors on certain policy issues. In this filing, the petitioners request that the Commission require ISO-NE, when it becomes an RTO, and the New England participating Transmission Owners to make certain communications and filings and to provide for the Committee's funding through a regional tariff.
Information Sharing by MMUs: What is permitted?	ISO-NE publishes quarterly and monthly reports on market performance. ISO-NE presents an annual review of market operations. Government agencies can make written requests for non-public information.	ISO-NE will publish a monthly report, available to the public, containing an overview of the market's performance in the most recent period. NEPOOL SMD, Appendix A, Section 11.2.1, Original Sheet No. 224. ISO-NE also will publish a quarterly report made available to appropriate state or federal government agencies. The content of the report will be updated periodically and is subject to confidentiality protection consistent with the NEPOOL Information Policy, which prevents the inappropriate dissemination of competitively sensitive data to individual NEPOOL Participants. ISO-NE will make available to the public a redacted version. ISO-NE will present an annual review of operations of the NEPOOL Market, which will include a public forum to discuss the performance of the NEPOOL Market, the state of competition and ISO-NE's priorities for the coming year. ISO-NE will arrange a non-public meeting open to appropriate state or federal government agencies, subject to the confidentiality protections of the ISO Information Policy. The quarterly and annual reports will inform the jurisdictional state and federal regulatory agencies, as well as the NEPOOL Markets Committee, if: (1) ISO-NE determines that a market problem appears to be developing that will not be adequately remediable by existing Market Rules or Mitigation Measures; (2) ISO-NE receives information from any entity regarding an alleged violation of law, refer the entity to the appropriate state or federal

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		agencies; (3) ISO-NE reasonably concludes that certain market behavior constitutes a violation of law. ISO-NE must report these matters to the appropriate state and federal agencies, and provide the names of any companies subjected to mitigation under these procedures as well as a description of the behaviors subjected to mitigation and any mitigation remedies applied. Information identifying particular participants required or permitted to be disclosed to jurisdictional bodies shall be provided in a confidential report filed under section 388.112 of the Commission regulations. Authorized government agencies can make written requests for information not permitted by the Information Policy. ISO-NE must notify each party with an interest in the confidentiality of the information. The information may be disclosed only if: (1) the authorized government agency has served ISO-NE with compulsory process; or (2) the interested party or parties have agreed with the requesting authorized government agency to voluntary disclosure of the data or information subject to reasonable and appropriate terms protecting its confidentiality that are satisfactory to those parties. NEPOOL SMD, Appendix A, section 11, Original Sheets Nos. 224-226.
PJM **MMUs** **MMU Independence**	Market Monitoring Unit consists of full-time PJM employees, is subject to the President's and the Board's oversight, and has authority to refer certain matters directly to the Board.	The MMU is comprised of full-time employees of PJM LLC, and it is subject to the President's and/or the Board's oversight. Tariff, Attachment M, V.B, Second Revised Sheet No. 450. Both the President and MMU have independent, discretionary authority to refer matters governed by the Market Monitoring Plan to the PJM Board. Tariff, Attachment M, V.D. MMU is to prepare and submit report to PJM Board, the Commission and other Authorized Government Agencies, and, if appropriate, the PJM Members Committee concerning the state of competition within, and the efficiency of the PJM Market. Tariff, Attachment M, VII.
MMU Responsibilities and Authority	Market Monitoring Unit oversees operational, compliance, and enforcement issues, ensuring that such monitoring function remains independent and objective.	MMU is responsible for: (1) monitoring and reporting on issues relating to the operation of the PJM Market; (2) through a demand letter evaluating the operation of both pool and bilateral markets; (3) evaluating any proposed enforcement mechanisms; and (4) ensuring that the monitoring program will be conducted in an independent and objective manner. Tariff, Attachment M, I. MMU is responsible for monitoring: (1) compliance with rules, standards, procedures, and practices of PJM Market; (2) actual or potential design flaws in the rules, standards, procedures, and practices of PJM Market and structural problems that may inhibit development of competitive market; (3) potential exercise of undue market power. Tariff, Attachment M, III.

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		MMU may take the following actions: (1) engage in discussion to inform Market Participants about rules, etc., or to attempt informal resolution a compliance or other issue; (2) recommend modifications to Tariff, OA, Reliability Assurance Agreement, Manuals, or other rules, etc.; (3) request Market Participant to discontinue non-compliant action; (4) bring matters not resolved through informal action before Members Committee, other PJM Committees, or the Board; (5) file reports or complaints, or make other appropriate filings, with Authorized Government Agencies; and (6) consider and evaluate additional enforcement mechanisms. Tariff, Attachment M, IV.B. MMU must notify the Commission upon determination of a significant market problem that requires further investigation, modification of the tariff or rules, or action by FERC or a state commission. Tariff, Attachment M, IV.A. MMU develops indices or standards to evaluate the information it collects and maintains. Tariff, Attachment M, VI.E. MMU must appropriately compensate Market Sellers who are under-compensated due to specific preexisting binding commitments. OA, Schedule 1, 3.2.3(f-3),. MMU submits reports and makes recommendations to Board and Members Committee with regard to any matter in its purview. Tariff, Attachment M, VII.A. For example, MMU reviews the Economic LRP following each summer period and audits load reduction data. . Under the Economic LRP, PJM may investigate participant behavior and claims under this program and may take actions as described under the PJM Market Monitoring Plan.
Market Power Mitigation		
MMU's Relationship to State Commissions	Market Monitoring Unit submits reports to authorized government agencies, as required by the PJM Tariff. PJM is committed to facilitating interregional monitoring.	MMU submits reports to the state commission(s) that it provided to the Board to Authorized Government Agencies, as well as other reports requested by such agencies. Tariff, Attachment M, VII.B. *See also* Memorandum of Understanding Among the New England, New York and PJM Independent System Operators Concerning Interregional Coordination Activities, dated Aug. 9, 1999. The OI and/or MMU may disclose confidential information to an Authorized Commission only if: it has executed with the OI a Non-Disclosure Agreement, prohibiting the recipient from sharing such information with third parties and the Authorized Commission; provides the OI with a final Commission order prohibiting release of disclosed information under terms of the OA and the Non-Disclosure Agreement; and (iii) any other necessary orders issued by the Authorized (State) Commission and state certifications. OA, section 18.17.4. *See also PJM*

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		Interconnection, LL.C., 107 FERC ¶ 61,322 (2004).
Information Sharing by MMUs: What is permitted?	Market Monitoring Unit protects confidential, proprietary, or commercially sensitive information but may make other data public in order to comply with PJM's obligations.	MMU keeps confidential discussions with Market Participants concerning informal resolution of compliance issues and demand letters sent to Market Participants. Tariff, Attachment M, IV.C. MMU regularly collects and maintains necessary information; MMU makes publicly available a detailed description of the categories of data collected. Tariff, Attachment M, VI.D. Notwithstanding anything to the contrary in the MMU Plan or the PJM OA, the MMU may disclose any information to comply with reporting obligations to Commission. Tariff, Attachment M, IV.C.3. MMU prepares a detailed public annual report about the it's activities, subject to PJM's obligations to protect confidential, proprietary, or commercially sensitive information, as well as ongoing investigations or monitoring activities. Tariff, Attachment M, VII.C.
SPP	Currently, SPP only has a basic framework for market monitoring. SPP's proposed framework provides for an independent market monitor (IMM) of requisite experience and qualifications to oversee the safe and reliable operation of the transmission system. The SPP Board of Directors has contracted with Boston Pacific to be the IMM. Marketing monitoring functions will include: --Monitoring and reporting on compliance and market power issues relating to transmission services (including congestion management, ancillary services, and the ability of a market participant to exercise market power by affecting available transmission capacity); --Evaluation and	To date, SPP has only filed a basic framework for market monitoring with the Commission. Under that framework, SPP "shall establish and provide appropriate support to a market monitoring function through an independent contractor possessing the requisite experience and qualifications." See Revised SPP OATT, Attachment X, Original Sheet No. 285. Both Attachment X to SPP's Revised OATT, and section 3.17 of the Revised By-Laws, list the market monitoring functions as follows: a. Monitoring and reporting on compliance and market power issues relating to transmission services, including compliance and market power issues involving congestion management and ancillary services and the potential of any market participant(s) to exercise market power within the region by affecting available transmission capacity; b. Evaluation and recommendation of any required modifications to the OATT, standards or Criteria; c. Ensuring that the monitoring program is conducted in an independent and objective manner; d. Development of reporting procedures to inform governmental agencies and others concerning market monitoring activities; e. Monitoring the behavior of market participants to determine whether there is any behavior that hinders the reliable, efficient and non-discriminatory provision of transmission service by SPP; f. Ensuring that SPP's involvement in markets does not discriminate in favor of any market participant or its own interests; and g. Developing plans for mitigating market power, subject to appropriate regulatory approval.

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	recommendation of changes to the OATT; --Ensuring that monitoring remains independent and objective; --Developing reporting procedures to inform government agencies and others of market monitoring activities; --Monitoring the actions of market participants to determine if there is any behavior which hinders the reliable, efficient and non-discriminatory provision of transmission service; Ensuring that SPP's actions in markets do not discriminate in favor of a market participant or itself; --Developing market power mitigation plans.	Boston Pacific Company, Inc. was selected to be an IMM. The IMM will inform and report to the Board of Directors, State regulatory agencies, and the Commission. The IMM will be responsible for carrying out the market monitoring functions listed above. *See Southwest Power Pool, Inc.*, 108 FERC ¶ 61,003 at P 93 (2004); and *Southwest Power Pool, Inc.*, 106 FERC ¶ 61,110 at P 163-164 (2004). The Commission required SPP to "provide a market monitoring plan which includes appropriate market power mitigation measures to address market power problems in the spot markets and a clear set of rules governing market participation conduct with the consequences for violations clearly spelled out." *Id*. at P 173. Additionally, the Commission required SPP's market monitoring plan to include "the process that the IMM would used [sic] if the IMM thinks the markets are not resulting in just and reasonable prices or providing appropriate incentives for investment in needed infrastructure," and to require that the IMM make periodic reports including market metrics to judge market performance. *Id*. The Commission required SPP to file its market monitoring plan no later than 60 days prior to implementing the third increment of Phase 1 of the energy imbalance market, which is to include the offer-based energy imbalance market, along with market monitoring and market power mitigation. *See Southwest Power Pool, Inc.*, 109 FERC ¶ 61,010 at P 69 (2004). In *Southwest Power Pool, Inc.*, 108 FERC ¶ 61,003 (2004), the Commission required that the contract "clearly reflect that the IMM may not: (1) directly represent market participants within SPP's region in proceedings before state regulators or this Commission; (2) work for clients with SPP-related business interests; or (3) work for clients that have business interests in markets inextricably connected to SPP (such as the Midwest ISO)." In *Southwest Power Pool, Inc.*, 109 FERC ¶ 61,009 (2004), the Commission accepted SPP's proposal to have the Board of Directors review engagements that could raise conflict of interest concerns, stating that such an approach "further[s] the ability of the IMM to undertake its function fairly and objectively with the confidence of the Board and market participants." As a result, the Commission required SPP to include in the IMM agreement the following language: "Before the Boston Pacific Team accepts any engagement that involves clients with SPP-related business interests or clients with business interests in markets inextricably connected to SPP, it must inform the SPP Board of Directors of such potential engagement and obtain the Board's determination that such engagement would not present a conflict of interest or result in the material

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		appearance of conflict before accepting such engagement." *Id.* at P 85.

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CAISO **Day-Ahead Market**	The Day-Ahead Market is the market for Energy and Ancillary Services which closes with CAISO's acceptance of the Final Day-Ahead Schedule. CAISO requires each SC to submit a balanced schedule in which resources and load are balanced. The current CAISO market structure does not have a Day-Ahead Spot Energy Market. The Day-Ahead Energy market is not financial binding, but the Day-Ahead Ancillary Services market is financial binding.	The Day-Ahead Market is the market for Energy and Ancillary Services which closes with CAISO's acceptance of the Final Day-Ahead Schedule. CAISO's scheduling process is contained in section 2.2.8 ("The Scheduling Process"), and requires each SC to submit a balanced schedule in which resources and load are balanced. CAISO Tariff § 2.2.7.2; CAISO Tariff, Scheduling Protocol (SP) 3.1. The currently operated day-ahead scheduling process does not require that schedules be feasible. The acceptance of infeasible schedules has led to a host of congestion management problems for CAISO. *See California Independent System Operator Corp.*, 103 FERC ¶ 61,265 at P 16-44 (2003). The deadline for submitting a Preferred Schedule in the day-ahead market is 10:00 a.m. At 11:00 a.m. CAISO: (1) notifies all SCs if inter-zonal congestion exists; (2) informs all SCs their advisory dispatch schedules if inter-zonal congestion exists; and (3) inform all SCs advisory Ancillary Service schedules and prices if inter-zonal congestion exists. CAISO Tariff, Appendix C (ISO Scheduling Process). SCs are required to submit revised preferred schedules and price bids, and Ancillary Service schedules and price bids to CAISO by 12:00 p.m. CAISO publishes final schedules at approximately 1:00 p.m. SP 3.2. The current CAISO market structure does not have a Day-Ahead Spot Energy Market.
Real-time Market/Spot Market	CAISO controls and coordinates the real-time Imbalance Energy (Real-Time Market). Under the current CAISO Real-Time Market, Zonal Energy Market, supply resources are dispatched in real-time to correct for zonal imbalances between	CAISO controls and coordinates the Real-Time Market. Zonal Energy Market, supply resources are dispatched in real-time to correct for zonal imbalances between supply and demand. Separate dispatches and payment uplifts are made to supply resources to manage congestion on transmission paths that were not recognized in the Day-Ahead Congestion Management Market; *i.e.*, Intra-Zonal Congestion. Instructed and Uninstructed Imbalance Energy is priced using the BEEP Interval Ex Post Prices.[6] CAISO Tariff § 2.5.23.

[6] BEEP Interval Ex Post Prices means the prices charged to or paid by SCs for Imbalance Energy in each Zone in each BEEP Interval.

7 The MSC supported the $250/MWh bid cap which was adopted by the Commission, despite the absence of a long-term adequacy requirement. *California Independent System Operator Corp.*, 100 FERC ¶ 61,060 at P 46 (2002).

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	supply and demand.	
Treatment of RMR Units	CAISO's Market Redesign and Technology Upgrade (MRTU) proposal includes the following elements: (1) a must-offer obligation (2) a bid cap of $250/MWh on energy and ancillary services[7] (3) automatic mitigation procedures that apply a price screen, a conduct test and a market impact test to each bid (System AMP);[8] (4) Local AMP which applies a market impact test to out-of-merit order bids; and (5) use of RMR contracts (RMR Agreements). RMR Agreements are designed to enhance grid reliability, meet local reliability needs, and manage intra-zonal congestion, and follow a standard format. An RMR Agreement between CAISO and a generator permits CAISO to call upon the generator to generate Energy or provide Ancillary Services when required to ensure the reliability of the Grid.	CAISO's MRTU proposal concerning market power mitigation elements were approved by the Commission on July 17, 2002, and implemented as 'Phase 1A' on October 31, 2002. *See California Independent System Operator Corp*., 100 FERC ¶ 61,060 (2002); *Order Granting in Part the Request for Extension of Time of the Sunset Date of the Existing California Energy Market Design*, 100 FERC ¶ 61,351 (2002). Elements of the proposal include: (1) a must-offer obligation that required generators (located in California, including non-public utility sellers) to offer CAISO all of their capacity in real time during all hours if it is available and not already scheduled to run through bilateral agreements; (2) a bid cap of $250/MWh on energy and ancillary services[9] (3) System AMP; (4) Local AMP which applies a market impact test to out-of-merit order bids; and (5) use of RMR Agreements). RMR Agreements are specialized service agreements used by CAISO to enhance grid reliability, meet local reliability needs, and manage intra-zonal congestion, and follow a standard format. An RMR Agreement between CAISO and a generator permits CAISO to call upon the generator to generate Energy or provide Ancillary Services when required to ensure the reliability of the CAISO Controlled Grid. *See California Independent System Operator Corp*., 87 FERC ¶ 61,250 (1999) (The Commission approved a *pro forma* RMR Agreement governing the terms and conditions under which each owner of an RMR unit provides RMR services to CAISO); CAISO Tariff section 5.2.6 and Appendix G. <u>Use of Cost Caps</u> - CAISO Tariff § 28 contains a rule limiting certain Energy and Ancillary Service bids. The maximum bid level is $250/MWh. Market Participants may submit bids above $250/MWh, however, any accepted bid above this cap are not

[8] System AMP applies: (1) a price screen, where the price must exceed $ 91.87 before zonal mitigation occurs; (2) a conduct test, which examines whether the bid deviates from the unit's reference price by the lesser of 200 percent or $ 100, and (3) an impact test, which tests to examine if the bid increases the zonal price by the lesser of 200 percent or $50. Under System AMP, if a resource fails the conduct and impact tests, its bid is replaced with its reference price, typically the rolling average of accepted bids over the past 90 days. *See California Independent System Operator Corp*., 100 FERC ¶ 61,060 at P 67 (2002).

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	-- The CAISO Tariff contains a rule limiting certain Energy and Ancillary Service bids. The maximum bid level is $250/MWh. Accepted bids above this cap are not eligible to set the Market Clearing Price and are subject to cost-justification and refund.	eligible to set the Market Clearing Price and are subject to cost-justification and refund. CAISO Tariff § 28.1.2.
Congestion Management	CAISO's congestion management system is a zonal model that differentiates between inter-zonal and intra-zonal congestion. Congestion is managed using adjustment bids to ration available transmission capacity. CAISO's current congestion management system uses Firm Transmission Rights (FTRs), which are contractual rights that entitle the FTR holder to receive a share of any net congestion revenues received by CAISO for the use of a specific congested inter-zonal interface (FTR paths are for only one direction). FTR holders are not entitled to the congestion charge revenues if the inter-zonal congestion is the opposite direction. Any entity (with the exception of CAISO) is eligible to acquire FTRs by participating in either CAISO's auction of FTRs, or by purchasing FTRs in the secondary market. FTRs are available on an annual basis	CAISO's congestion management system is based on a zonal model that differentiates between two kinds of congestion: inter-zonal and intra-zonal congestion. Inter-zonal congestion management refers to the management of congestion between zones. Under the current CAISO rules, forward inter-zonal schedules are limited to the available transmission capacity between each zone. Congestion is managed using adjustment bids to ration available transmission capacity. Intra-zonal congestion management refers to the management of congestion within a zone. Intra-zonal congestion, unlike inter-zonal congestion, is managed in real-time in the energy imbalance market for supplemental energy. *See California Independent System Operator Corp.*, 105 FERC ¶ 61,140, at P 30 n.19 (2003). CAISO's current congestion management system uses FTRs. CAISO Tariff § 9.2. An FTR is a contractual right that entitles the FTR holder the right to receive a share of any net congestion revenues received by CAISO for the use of a specific congested inter-zonal interface during a given hour. Each FTR is defined by a transmission path from a designated originating zone to a designated receiving zone. In addition, the FTR path is for only one direction. See id.; CAISO Tariff § 9.2.1. An FTR holder is entitled to share net congestion charges attributable to inter-zonal congestion for transfers on that path from the designated originating zone to the designated receiving zone. FTR holders are not entitled to the charge if the inter-zonal congestion is the opposite direction. CAISO Tariff § 9.6.1. Allocation of FTRs - Any entity (with the exception of CAISO) is eligible to acquire FTRs by participating in either CAISO's auction of FTRs, or by purchasing FTRs in the secondary market. The FTRs are available on an annual basis through an FTR auction that commences approximately two months before the actual term of the FTR. Additionally, entities that hold existing transmission contracts who become PTOs are allocated FTRs. The amount of FTRS shall be determined when the Transmission Control Agreement is executed and shall be commensurate with the Transmission capacity the new Participating TO turns over to ISO Operational Control. FTRs

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	through an FTR auction that commences approximately two months before the actual term of the FTR.	associated with converted rights shall terminate on the earlier of termination of the existing contract or the end of the 10 year transition period. See Tariff § 9.4.3, see also Appendix F Schedule 3. Auction revenues received by CAISO for FTRs are allocated and paid to Participating Transmission Owners (TO) that are entitled to receive the congestion revenues associated with inter-zonal interfaces. The CAISO Tariff also states that a FTR holder is entitled to receive a portion of the total congestion revenues related to inter-zonal congestion in both the day-ahead and hour-ahead markets.
Rate Design/Pricing (e.g., license plate, postage stamp and regional through and out rates)?	All Market Participants withdrawing Energy from the CAISO Controlled Grid will pay Access Charges, which are designed to recover each Participating TO's Transmission Revenue Requirements The Real-Time Market charges for the costs of purchasing Instructed and Uninstructed Imbalance Energy, and Regulation Energy Payment Adjustments. Any SC scheduling a Wheeling transaction will pay CAISO the applicable Wheeling Access Charge; and (2) the total hourly schedules of Wheeling in kilowatt-hours for each month at each Scheduling Point associated with that transaction.	CAISO's Transmission Access Charge (TAC) rate (currently being litigated in Docket No. ER00-2019-000) has a ten-year transition period starting in January 2001, in which it will go from three separate TAC area rates to a single system grid-wide rate. During the transition period, which is now in its fourth year, CAISO calculates the separate TAC area rates based on the Transmission Revenue Requirement of the Participating Transmission Owners in each TAC area. The North TAC area only has PG&E; the South TAC area only has San Diego Gas & Electric Company; the East/Central TAC area has SoCal Edison and the Cities of Azusa, Anaheim, Banning Riverside and Vernon, CA. High voltage TAC area rates are a hybrid of 60 percent area specific revenue requirement and 40 percent rolled in rate component (the average rate of 40 percent of the combined TRRs of all PTOs and the Revenue Reqt associated with all new transmission facilities added after January 2001). So, the high voltage is transitioning toward postage stamp but still has a license plate flavor.
MISO **Day-Ahead Market**	Customers may obtain day-ahead firm transmission service in Midwest ISO. Midwest ISO proposes to use Locational Margainal Pricing (LMP) to settle energy sales and purchases, calculate transmission charges and settle the FTRs in the Day-Ahead Market.	On March 31, 2004, MISO filed a proposed Open Access Transmission and Energy Markets Tariff (TEMT) containing terms and conditions necessary to implement a market-based congestion management program, including a Day-Ahead Energy Market, Real-Time Energy Market and Financial Transmission Rights (FTR_ Market. The proposed effective date for the changes in the TEMT is December 1, 2004 however, in an order issued on May 26, 2004 (107 FERC ¶ 61,191), the Commission moved the date for implementation of the TEMT to March 1, 2005. The TEMT sought to implement a centralized security-constrained economic dispatch platform supported

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	Midwest ISO provides FTRs to hedge congestion charges in the Day-Ahead market.	by a Day-Ahead and Real-Time Energy market design, including Locational Margainal Pricing and Financial Transmission Rights within the Midwest ISO region. The Midwest ISO will use FTRs to hedge congestion charges in the Day-Ahead Market. Midwest ISO will use LMP to settle energy sales and purchases, to calculate transmission usage charges and to settle FTRs in the Day-Ahead Market . Aspects of this issue are currently on rehearing before the Commission and will be decided in the future. *See* 108 FERC ¶ 61,163 (2004). Midwest ISO provides FTRs to hedge congestion charges in the Day-Ahead Market. Midwest ISO directly allocates FTRs to existing users of the transmission network. *See* 108 FERC ¶ 61,163 (2004). Aspects of this issue are on rehearing before the Commission and will be decided in the future.
Real-time Market/Spot Market	Midwest ISO's TEMP provides for a Real-Time Energy Market. Midwest ISO uses LMP to settle energy sales and purchases and to calculate transmission usage charges in the Real-Time Energy Market.	Midwest ISO's TEMP uses Locational Marginal Pricing to settle energy sales and purchases and to calculate transmission usage charges in the Real-Time Market. *See* 108 FERC ¶ 61,163 (2004).
Treatment of RMR Units	Midwest ISO does not have RMR units, however, they do have a System Supply Resources program that will ensure reliable grid operation by impeding the exit of uneconomic units when it would jeapordize reliability.	Midwest ISO has the authority to designate reliability must run units using NERC criteria (but it has not designated any such units). Midwest ISO FERC Electric Tariff, Second Revised Volume No. 1, Substitute Original Sheet No. 324 (Effective April 1, 2002 – deferred until energy markets are operative). Midwest ISO has no RMR units, but the March 30, 2004 TEMT filing provides for System Supply Resources (SSR) units that serve a similar function. To assure reliable grid operation, the Midwest ISO will implement s SSR program that will allow it to negotiate compensation for selected units that are uneconomic, but needed for reliability reasons. This program will help Midwest ISO address the concern the reliability could be compromised by the exit of uneconomic resources. Midwest ISO's SSR program would impede competitive exit for a limited period when exit would jeapordize reliability. The SSR program also provides general guidelines for compensating SSR units. Aspects of this issue are currently on rehearing before the Commission and will be decided in the future. *See* 108 FERC ¶ 61,163 (2004). During the transition period, the ISO cost recovery adder is capped at $.15/MWh.

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		Midwest ISO FERC Electric Tariff, Second Revised Volume No. 1, Substitute Second Revised Sheet No. 211 (Effective March 1, 2003).
Congestion Management	The Midwest ISO Day 1 congestion management system promotes greater use of generation redispatch relative to curtailment, encourages regional coordination, and is administered by an independent entity. The Midwest ISO Day 2 congestion management system, when proposed, will provide for: (1) a security-constrained, centralized bid-based scheduling and dispatch system (i.e., day-ahead and real-time market rules); (2) FTRs for hedging congestion costs (FTR Rules); and (3) market settlement rules. Firm point-to-point transmission customers may offer to resell their reservations/entitlements (FTRs) to capacity across constrained lines. Midwest ISO proposes to use FTRs to hedge congestion charges in the Day-Ahead market. Midwest ISO currently uses NERC TLR procedures for congestion management.	Type – Midwest ISO uses NERC TLR procedures for congestion management, located in Attachment Q of the Midwest ISO Tariff. Midwest ISO FERC Electric Tariff, Second Revised Volume No. 1, Substitute Original Sheet No. 318 (Effective April 1, 2002 – deferred until energy markets are operative) (Filed pursuant to *Midwest ISO*, 101 FERC ¶ 61,174 (2002)). The Commission determined that Midwest ISO's proposal for congestion management was a reasonable initial approach to managing congestion and satisfied the requirements of Order No. 2000 for Day 1 operation of an RTO. It directed Midwest ISO to coordinate its Day 2 congestion management efforts with the pending rulemaking on Standard Market Design. *Midwest ISO*, 97 FERC ¶ 61,326 (2001) (December 20 Order), *reh'g denied*, 103 FERC ¶ 61,169 (2003). Midwest ISO provides FTRs to hedge congestion charges in the Day-Ahead Market. *See* 108 FERC ¶ 61,163 (2004).
Rate Design/Pricing	Midwest ISO, which currently employs a license plate rate methodology for transmission service. Midwest ISO plans to implement locational marginal pricing (LMP) for its energy markets.	Midwest ISO proposes to use LMP to settle energy sales and purchases in the Day-Ahead and Real-Time Energy markets. Midwest ISO also uses LMP to calculate transmission usage charges in both markets and to settle the FTRs in the Day-Ahead market. The Commission approved the use of LMP with additional clarifications and market safeguards to protect against extremely high prices. The Commission encouraged members to rely on the independent market monitor to ensure market

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	The Commission required Midwest ISO to: (1) clarify certain conditions, (2) implement certain market safeguards, and (3) eliminate regional through and out rates by December 1, 2004. The Commission is currently considering proposals to eliminate regional through and out rates.	safeguards and required a bid cap of $1000/Mw-Hour (the same as in the eastern ISOs) to protect against extremely high market prices.
NYISO **Day-Ahead Market**	NYISO operates both day-ahead and real-time markets The day-ahead market closes at 5:00 AM for the following day.	NYISO administers a day-ahead market in which capacity, energy, and ancillary services are scheduled and sold for the following day. The day-ahead market closes at 5:00 AM for the following day. NYISO operates its day-ahead market using software that performs a Security-Constrained Unit Commitment (SCUC). The SCUC simultaneously conducts markets to commit generation to meet energy, operating reserve, and regulation requirements based on the bids of market participants. The day-ahead market is a forward market in which hourly clearing prices are calculated for each hour of the next operating day based on Generation Offers, Demand Price Sensitive Bids, Virtual Supply Offers, Virtual Demand Bids, and self schedules submitted into the day-ahead market. Bilateral schedules are accepted in the day-ahead SCUC process and are accompanied by incremental and decremental bids. The day-ahead scheduling process will incorporate NYISO reliability requirements and reserve obligations into the analysis. Based on the load forecast, NYISO will issue day-ahead unit commitment to meet forecast demand and reserve requirements, and it establishes day-ahead schedules for each generator. The resulting day-ahead hourly schedules and day-ahead LMPs represent binding financial commitments to the Market Participants. All generators that are installed Capacity Resources in New York are required to either bid into the day-ahead energy Market, be scheduled in a day-ahead bilateral transaction to serve load in the New York Control Area, or be unavailable due to maintenance, forced outage, or temperature derating. The hourly energy prices, locational marginal prices LMPs, are calculated for each generator location within New York, eleven load zones, and four proxy buses reflecting the regions bordering New York (PJM, NEPOOL, Ontario and Hydro Quebec). Bilateral schedules pay a day-ahead transmission usage charge to the ISO that is calculated from the difference between the LMPs at the source and sink locations. Day-ahead settlements for reserves and regulation are presently based on a single market-clearing availability price. FTRs are accounted for at the day-ahead LMP values.

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Real-Time Market	The Real-time Market closes 75 minutes before the hour being scheduled. NYISO allows virtual bidding by various resources. Virtual trading allows entities that do not serve load to make purchases in the day-ahead market.	NYISO administers a day-ahead market in which capacity, energy, and ancillary services are scheduled and sold for the following day. The day-ahead market closes at 5:00 AM for the following day. NYISO operates its day-ahead market using software that performs a Security-Constrained Unit Commitment (SCUC). The SCUC simultaneously conducts markets to commit generation to meet energy, operating reserve, and regulation requirements based on the bids of market participants. The day-ahead market is a forward market in which hourly clearing prices are calculated for each hour of the next operating day based on Generation Offers, Demand Price Sensitive Bids, Virtual Supply Offers, Virtual Demand Bids, and self schedules submitted into the day-ahead market. Bilateral schedules are accepted in the day-ahead SCUC process and are accompanied by incremental and decremental bids. The day-ahead scheduling process will incorporate NYISO reliability requirements and reserve obligations into the analysis. Based on the load forecast, NYISO will issue day-ahead unit commitment to meet forecast demand and reserve requirements, and it establishes day-ahead schedules for each generator. The resulting day-ahead hourly schedules and day-ahead LMPs represent binding financial commitments to the Market Participants. All generators that are installed Capacity Resources in New York are required to either bid into the day-ahead energy Market, be scheduled in a day-ahead bilateral transaction to serve load in the New York Control Area, or be unavailable due to maintenance, forced outage, or temperature derating. The hourly energy prices, locational marginal prices LMPs, are calculated for each generator location within New York, eleven load zones, and four proxy buses reflecting the regions bordering New York (PJM, NEPOOL, Ontario and Hydro Quebec). Bilateral schedules pay a day-ahead transmission usage charge to the ISO that is calculated from the difference between the LMPs at the source and sink locations. Day-ahead settlements for reserves and regulation are presently based on a single market-clearing availability price. FTRs are accounted for at the day-ahead LMP values.
Treatment of RMR Units	NYISO does not have any RMR units. NYISO currently has a $1000/MWh bid cap for energy in New York which is expected to continue for the immediate future.	NYISO does not have any RMR units. Use of Bid Caps **–** There is currently a $1000/MWh bid cap for energy in New York which is expected to continue for the immediate future. Day-ahead bid caps also apply to some generating units to mitigate market power. There are Commission-approved caps on the bids of certain plants located within New York City that have been divested by Consolidated Edison. These bid caps apply when certain congestion patterns exist, and the applicability of these bid caps is determined in an initial step in the Security-Constrained Unit Commitment (SCUC) software. There is also currently a $2.52/MWh

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		bid cap on availability bid offers for 10-minute non-spinning reserves to mitigate market power in the 10-minute reserve market. *See* Attachment F "Temporary Bid Caps" to NYISO's Market Administration and Control Area Service Tariff.
Congestion Management	NYISO offers both firm and non-firm transmission service. Customers requesting firm service agree to pay the congestion charges associated with their scheduled service. Non-firm service is available for customers who do not want the ISO to schedule their transaction if it would require payment of a congestion charge. Transmission service under the NYISO is made available on a long-term fixed-price basis through the seasonal auction of Transmission Congestion Contracts (TCCs).	NYISO offers both firm and non-firm transmission service. Customers requesting firm service agree to pay the congestion charges associated with their scheduled service. Non-firm service is available for customers who do not want the ISO to schedule their transaction if it would require payment of a congestion charge. Transmission service under the NYISO is made available on a long-term fixed-price basis through the seasonal auction of Transmission Congestion Contracts (TCCs). TCCs are FTRs that can be used to hedge day-ahead congestion costs incurred for a bilateral contract. Prior to the formation of the NYISO, the initial allocation of TCC's were made in two stages. The first stage permitted customers receiving service under existing transmission agreements to choose whether to convert their existing rights into either grandfathered rights or grandfathered TCCs. After these rights were allocated and accounted for, existing transmission capacity for native load was allocated to some transmission owners. Distribution of TCC auction revenues: All revenues received by transmission owners from the sale of: (1) grandfathered TCCs; (2) residual TCCs; and (3) excess auction revenues credited against transmission owners' cost of service, go towards reducing transmission service charges. See Attachment M "Sale of Transmission Congestion Contracts (TCC)" and Attachment N (Allocation of TCC Sales Revenues, Excess Congestion Rents and Congestion Rent Shortfall) of NYISO's OATT.
Rate Design / Pricing	NYISO uses a zonal LMP pricing mechanism that pays each generator the marginally accepted bid price for the energy it produces and delivers within a specified zone.	NYISO uses a zonal LMP pricing mechanism that pays each generator the marginally accepted bid price for the energy it produces and delivers within a specified zone. *See* Attachment J (Locational Based Marginal Price (LBMP) Calculation Method) of NYISO's OATT. *See also* Attachment B (LBMP Calculation Method) of NYISO's Market Administration and Control Area Service Tariff. *See also* Article 4.16 and 4.17 of NYISO's Market Administration and Control Area Service Tariff, for detailed explanation of how NYISO calculates the Day-Ahead and Real-Time LMPs.
ISO-NE **Day-Ahead Market**	Day-Ahead Market allows Participants to purchase and sell at Day-Ahead prices. Day-Ahead Market is financially binding.	Enables Participants to purchase and sell energy through the NEPOOL Market at Day-Ahead Prices and enable Participants to submit External Transactions conditioned upon Congestion Costs not exceeding a specified level. Participants whose purchases and sales and External Transactions are scheduled in the Day-Ahead Energy Market shall be obligated to purchase or sell energy or pay Congestion Costs and costs for losses, at the applicable Day-Ahead Prices for the amounts scheduled. NEPOOL Market Rule 1,

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	Participants must submit 3-part bids before Noon on the preceding day. Day-Ahead Offers must specify the Resource, amounts, and prices.	section 1.10.1(b), Original Sheet No. 29. The Day-Ahead Market is financially binding and encompasses Supply Offers as well as Demand Bids and Virtual Bids. Only Resources receiving credit for ICAP Resources are required to participate in the Day-Ahead Market. Units submit three-part bids (Start-Up, No-Load, and energy block) and recover as-bid costs following a comparison with market revenues received across an Operating Day. Before 12:00 noon on the day before the Operating Day in question, Participants may submit regulation offers and offers and bids for energy with the location and amount of their sales and loads/purchases, and the price at which they are willing to forgo purchasing in the Day-Ahead Energy Market. NEPOOL Standard Market Design, Transmittal Letter, Page 6. Resource offers must be in accordance with Offer Data requirements, including specification of the Resource, hourly amounts, and prices for the entire Operating Day. Units whose start-ups are cancelled by ISO-NE may be compensated through a pro-rata share of its Start-Up Fee. Participants may schedule Resources to satisfy all or portions of their load. External Transactions importing energy into the NEPOOL Control Area may offer system power or power from a specific External Resource.
Real-Time Market/Spot Market	Real-Time Market encompasses energy transactions, payment of Congestion Costs, and payment for Day-Ahead losses.	The market in which the purchase or sale of energy, payment of Congestion Costs, and payment for losses for quantity deviations from the Day-Ahead Energy Market in the Operating Day occurs. NEPOOL Market Rule 1, section 1, Original Sheet No. 19. For each Participant for each hour, ISO-NE determines a Real-Time Energy Market position that includes each Participant's: (i) Real-Time Load Obligation, (ii) Real-Time Generation Obligation, (iii) Real-Time Adjusted Load Obligation, and (iv) Real-Time Locational Adjusted Net Interchange. NEPOOL Market Rule 1, section 3.2.1, Original Sheet No. 53. Participants are able to Self-Schedule the output of their Resources on an hour-by-hour basis by notifying ISO-NE at least an hour in advance of the requested hourly change. NEPOOL Standard Market Design, Transmittal Letter, Page 8.
Treatment of RMR Units	Participants may self-schedule hourly one hour in advance. ISO-NE chooses RMR units on a non-discriminatory basis, and then dispatches those units in times of constraints.	RMR Units are those Resources identified by ISO-NE on a daily basis as necessary for the provision of Operating Reserve requirements and adherence to NERC, NPCC, and NEPOOL reliability criteria over and above those Resources required to meet first contingency reliability criteria within a Reliability region. When establishing operating schedules, ISO-NE: (i) selects RMR Resources on a not unduly discriminatory basis, and determines which, if any, Supply Offers will be

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	ISO-NE's bid cap is currently $1,000 per MWh.	adjusted; and (ii) dispatches generating Resources to provide relief for constraints not reflected in ISO-NE's systems for operating the NEPOOL transmission system or ISO-NE's operating procedures in accordance with the procedures defined in the NEPOOL manuals. NEPOOL Market Rule 1, section 6, Original Sheet No. 71. RMR Operating Reserve Payments, Daily RMR Resource Operating Reserves Charges, and Allocation of Fixed Cost Charges Associated with RMR Contracts are calculated based on the methods detailed in sections 6.4.3 and 6.4.4. (Original Sheets 71-72) <u>Use of Cost Caps</u> - ISO-NE uses bid caps. The current existing bid cap is $1,000 per MWH. This cap applies to ISO-NE's Energy, AGC, and Operating Reserve markets. *See ISO New England, Inc.*, 97 FERC ¶ 61,090 (2001).
Congestion Management	Congestion Management is reflected in LMP. Half of all FTRs are sold in an annual auction, the other half in monthly auctions. Participants in FTR auctions must satisfy a financial assurance requirement. FTR Auction bids must specify megawatt quantity, receipt and delivery points, and a reservation price. FTR Allocation is subject to simultaneous feasibility constraints.	<u>Type</u> - LMP. Congestion Costs shall be reflected in Location Marginal Prices. Congestion Costs shall be recovered from Non-Participant Transmission Customers taking service under the NEPOOL tariff. NEPOOL Tariff, section IVA (25A), 1st Revised Sheet No. 83. <u>FTR Allocation</u> - Periodic auctions, conducted by ISO-NE, to allow FTR Bidders to acquire or FTR Holders to sell FTRs. Non-Participants must satisfy the applicable financial assurance criteria and pay the one-time $5,000 FTR Registration Fee. Auctions are held monthly, with additional "long-term" FTR Auctions held beginning seven months following the effective date of SMD. An annual FTR auction will make available 50 percent of the feasible FTRs that will have a term of one year. The remaining fifty percent of FTRs, which will have terms of one month, will be made available in monthly auctions. NEPOOL Market Rule 1, section 7.1, Original Sheet Nos. 73-74. ISO-NE will conduct separate auctions simultaneously for on-peak and off-peak periods. Offers to sell must identify the specific FTRs, by megawatt quantity and receipt and delivery points, a reservation price, and may not specify a minimum quantity being offered. Bids to purchase must specify the megawatt quantity, price per megawatt, and receipt and delivery points, but may not specify a minimum quantity that the bidder wishes to purchase. The winning bids are determined from a linear programming model that selects the set of simultaneously feasible FTRs with the highest net total auction value. In a tie where there are insufficient FTRs to accommodate all identical bids, then each such bidder will receive a pro rata share. FTRs are sold at the market-clearing price for FTRs between specified pairs of receipt and delivery points, as determined by the bid value of the marginal FTR that could not be awarded because of simultaneous feasibility constraints. FTR Holders may trade

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		FTRs on the secondary market and have these settled using ISO-NE systems, which only allow FTRs to be sub-divided into multiple FTRs with: (i) the same points of injection and withdrawal; (ii) different megawatt amounts the sum of which does not exceed the original FTR MW amount; and (iii) different start and end dates where the start and end dates are the same as or within the start and end dates of the original FTR. FTRs may be reconfigured only through FTR Auctions. NEPOOL Market Rule 1, section 7.3, Original Sheet Nos. 75-78.
Rate Design/Pricing	ISO-NE uses a license-plate rate, as well as a Through and Out Rate. An Internal Point-to-Point rate covers firm or non-firm Internal Point-to-Point Service. Network Customers pays for any Direct Assignment Facilities and its share of the cost of any required upgrades to the PTF. Generator Interconnection-related Upgrade Costs are allocated consistent with Schedule 11 of the ISO-NE Tariff. Elective transmission upgrades, Local Benefit Upgrades, Merchant Transmission Facilities, and Localized Costs are not Pool-Supported PTF costs. All Regional Benefit Upgrades are Pool-Supported PTF costs.	NEPOOL employs a postage stamp rate design, applicable to PTF, that includes a Through and Out rate: Each Participant or Non-Participant which takes Through or Out Service must pay to NEPOOL a charge per Kilowatt of Reserved Capacity based on an annual rate (the "the T or O Rate") which is the Pool PTF Rate, as well as ancillary service charges. The rate per hour for the T or O Rate, applicable only to Non-Firm T or O service, is the annual Pool PTF Rate divided by 8760. NEPOOL Tariff, section III (20), 2nd Revised Sheet No. 69; See Schedule 8 For Calculation of Through or Out Rate. Each Participant or Non-Participant which takes firm or non-firm Internal Point-to-Point Service pays to NEPOOL a charge per Kilowatt of Reserved Capacity based on an annual rate (the "IPTP Charge") which is the Internal Point-to-Point Service Rate; provided that if a rate which is derived from the annual incremental cost, not otherwise borne by the Transmission Customer or a Generator Owner, of any new facilities or upgrades that would not be required but for the need to provide the requested service is greater than the Pool PTF Rate, the IPTP Charge is the higher of such amounts. The Transmission Customer also must pay any ancillary service charges. NEPOOL Tariff, section III (21), 1st Revised Sheet No. 71. The Network Customer pays Transmission Providers for any Direct Assignment Facilities and its share of the cost of any required upgrades to the PTF, along with the payment to the System Operator of the charges for Ancillary Services and the charge for Regional Network Service. Regional Network Service rate is determined by Schedule 9 of the NEPOOL tariff. NEPOOL Tariff, section 46, 2nd Revised Sheet No. 176. <u>Participant Funding</u> - Concerning a Category A and B Generator Interconnection Related Upgrade Costs: One-half of the Shared Amount (as set forth in section c of Schedule 11 of the NEPOOL Tariff) of the capital cost of the PTF upgrade constitutes Pool-Supported PTF and be included in Annual Transmission Revenue Requirements. Category C Upgrade Costs will be allocated in the same manner as Reliability Upgrades if the System Operator determines that a particular Generator Interconnection Related Upgrade provides benefits to the system as a whole. NEPOOL Tariff, Schedule 11, 2nd

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		Revised Sheet No. 224. Costs associated with Reliability Upgrades and Economic Upgrades are recovered: (i) in accordance with the recovery mechanism for effected facilities that is filed and accepted by the Commission; or (ii) in the same manner used for Category C Generator Interconnection Related Upgrade Costs; or (iii) as dictated by any agreement containing a provision that allocates all or a percentage of the costs to a specific entity or entities; or (iv) if none of the above apply, the costs are treated as Pool-Supported PTF costs. NEPOOL Tariff, Schedule 12, 4th Revised Sheet No. 229. Generator Interconnection Related Upgrades will be allocated the same as above. Elective transmission upgrades will not be included in the Pool-Supported PTF costs. NEMA Upgrades, and RTEP02 Upgrades placed in service on or before December 20, 2007, shall be included in the Pool-Supported PTF costs for so long as such Transmission Upgrades continue to meet the definition of PTF and allocated to Transmission Customers taking service under the NEPOOL Tariff. All Regional Benefit Upgrades shall be included in the Pool-Supported PTF costs. Local Benefit Upgrades, Merchant Transmission Facilities, and Localized Costs shall not. NEPOOL Tariff, Schedule 12 (Superseding Previous Schedule 12), 2nd Revised Sheet No. 229C.
Scarcity Pricing	Intended to ensure that energy prices are set at efficient levels when the NEPOOL Control Area is short of Operating Reserves	The Scarcity Pricing Mechanism is an interim measure and is intended to ensure that energy prices are set at efficient levels when the NEPOOL Control Area is short of Operating Reserves. It is to be replaced when ISO-NE develops fully co-optimized energy and reserve markets. The mechanism sets the energy component of the LMP at $1000/MWh in shortage conditions to assure that the price of energy properly reflects its value as either energy or Operating Reserves. The dispatch algorithm includes in the calculation of LMPs the effect of losses from the marginal resource to the reference node, and thus it is possible for the energy component (the LMP at the reference node) to exceed $1,000. The mechanism applies only to real-time dispatch and the real-time market. ISO-NE will declare a Reserve Shortage Condition when it (1) is experiencing, or must take action to avoid experiencing, a deficiency in total ten minute Operating Reserves, or (2) is experiencing a deficiency in total operating reserves that has lasted longer than a four-hour period of time and has begun or is anticipating taking out-of-merit actions or engaging in emergency energy transactions to maintain or preserve Operating Reserves. Reserve Shortage Condition will be terminated when ISO-NE has determined that system conditions have improved to the point where out-of-merit dispatch is no longer needed to maintain required operating reserves. *See* NEPOOL SMD, Market Rule 1, section 2.5(d), 3rd Rev Sheet No. 48

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PJM **Day-Ahead Market**	Day-ahead Locational Marginal Prices are determined according to the considerations and calculations provided in the Operating Agreement.	Day-ahead Locational Marginal Prices shall be determined on the basis of the least-cost, security-constrained dispatch, model flows and system conditions resulting from the load specifications, offers for generation, dispatchable load, Increment Bids, Decrement Bids, and bilateral transactions submitted to the OI and scheduled in the Day-ahead Energy Market. The price calculation is made hourly by applying a linear optimization method to minimize energy costs, given scheduled system conditions, scheduled transmission outages, and any transmission limitations that may exist. OA, Schedule 1, 2.6, Original Sheet No. 106
Real-Time Market	The Real-time Price calculation is made, applying an incremental linear optimization method, in accordance with the provisions of the Operating Agreement. The Office of the Interconnection identifies facility outages and other system conditions that may cause system constraint, and which may require the dispatch of other generation resources. The Office of the Interconnection may determine that prices for energy offered by any resource must be limitedly capped in order to maintain system reliability.	<u>Market Sellers</u> - A Market Seller is credited for Real-time sales of Spot Market Energy to the extent of its hourly net deliveries to the PJM Control Area or PJM West Region of energy in excess of amounts scheduled in the Day-ahead Energy Market from the Market Seller's resources. The total Real-time <u>generation revenues</u> for each Market Seller is the sum of its credits determined by the product of (1) the hourly net amount of energy delivered to the PJM Control Area and PJM West Region at the applicable generation or interface bus in excess of the amount scheduled to be delivered in that hour at that bus in the Day-ahead Energy Market from each of the Market Seller's resources, times (2) the hourly Real-time Price at that bus. To the extent that the energy actually injected at a generation or interface bus is less than the energy scheduled to be injected at that bus in the Day-ahead Energy Market, the Market Seller is debited for the difference at the Real-time Price for the applicable bus at the time of the shortfall times the amount of the shortfall. OA, Schedule 3.3.1, Original Sheet No. 118.
Treatment of RMR Units		<u>Must-Run Reliability Units</u> - Not later than one hour prior to the scheduling deadline (*see* OA, Schedule 1, 1.10.1, Original Sheets Nos. 91-92), the OI identifies on the PJM Open Access Same-Time Information System any facility outage or other system condition which it has determined may give rise to a transmission constraint that may require, in order to maintain system reliability, the dispatch of one or more generation resources that otherwise would not be dispatched on the merits of their offers to the PJM Interchange Energy Market. OA, Schedule 1, 6, Original Sheets Nos. 129-30. <u>Price Caps</u> - With certain limits, if, at any time, it is determined by the OI in accordance with its scheduling responsibilities or must-run procedures (*see* OA, Schedule 1, 1.10.8, Original Sheet No. 98 and 6.1, Original Sheet No. 129) that any generation resource may be dispatched out of economic merit order to maintain system reliability as a result of limits on transmission capability, the prices for energy offered by such resource are capped. If the OI is able to do so, such prices are capped only during each hour when

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		the transmission limit affects the schedule of the affected resource, and otherwise are capped for the entire Operating Day, *i.e.*, 24-hour operating period. OA, Schedule 1, 6.4, Original Sheet No. 131 & First Revised Sheet No. 132. The price cap will be one of the following as specified by the Market Seller: (i) the weighted average Locational Marginal Price at the generation bus at which energy from the capped resource was delivered; (ii) the incremental operating costs plus 10 percent; or (iii) an amount determined by agreement between the OI and the Market Seller. *Id.* The Commission has directed PJM to revise its reliability compensation policy to provide the right to frequently mitigated units needed for reliability (*i.e.*, units that are offer capped for 80 percent or more of their run hours and are not recovering sufficient revenues to cover their costs) to receive higher offer caps or alternative compensation schemes. *PJM Interconnection, LL.C.*, 107 FERC ¶ 61,112 (2004).
Congestion Management	The Office of the Interconnection calculates congestion charges when the system is operating under constrained conditions. Transmission Congestion Credits, calculated based on each holder's Financial Transmission Rights, off-set congestion charges. The Daily and Monthly Capacity Credit Markets are competitive markets, operated for the purchase and sale of Capacity Credits for a business day or twelve-month period, respectively.	<u>Transmission Congestion Charges</u> - When the transmission system is operating under constrained conditions, the OI will calculate Transmission Congestion Charges for each Network Service User, the PJM Interchange Energy Market, and each Transmission Customer. The basis for such charges will be the differences in the Locational Marginal Prices between points of delivery and points of receipt. OA, Schedule 1, 5.1, First Revised Sheet No. 123 & Original Sheets 124-125. <u>Transmission Congestion Credits</u> - With certain limitations, each holder of a Financial Transmission Right will receive as a Transmission Congestion Credit a proportional share of the total Transmission Congestion Charges collected for each constrained hour. OA, Schedule 1, 5.2, Original Sheet No. 125; *see also id.* at 5.2.1(b), Original Sheet No. 125 and First Revised Sheet No. 126. <u>FTRs</u> - Transmission Congestion Credits will be calculated based upon the Financial Transmission Rights held at the time of the constrained hour. FTRs are defined from a point of receipt/injection to a point of delivery/withdrawal. The hourly economic value of an FTR is based on the FTR MW reservation and and the difference between day-ahead LMP at the sink/delivery point and the source/receipt point. OA, Schedule 1, 5.2.2, First Revised Sheet No. 126 *et seq.*; *see also id.* at 7.2, Substitute Original Sheet No. 133. FTRs can be obtained either through an Annual or Monthly FTR Auction, which is conducted by PJM or on through the bilateral Secondary Market. OA, Schedule 1, 7.1 *et seq.*, First Revised Sheet No. 132 *et seq.* <u>Auction Revenue Rights</u> (AARs) – AARs are the mechanism by which the proceeds from the Annual FTR Auction. AARs are allocated annually to Firm Transmission

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		Customers – i.e., to Network Transmission Service Customers (for Network Integration Service) and Firm Point-to-Point Transmission Customers (for Firm Point-to-Point Services) – that entitle the holder to receive an allocation of the revenues from the Annual FTR Auction. Such customers request AARs from PJM, which will approve part, all or none of the request based on a Simultaneous Feasibility Test. The economic value of AARs is based on the MW amount and on the Locational Marginal Price differences between the sources and the sink node for FTR obligations resulting from the Annual FTR Auction. AAR holders may also convert AARs into FTRs by "self-scheduling" an FTR into the Annual FTR Auction. OA, Schedule 1, 7.4, First Revised Sheet No. 136 *et seq. See generally PJM Interconnection, LL.C.*, 102 FERC ¶ 61,276 (2003); *PJM Interconnection, LL.C.*, 106 FERC ¶ 61,049 (2004); *PJM Interconnection, LL.C.*, 108 FERC ¶ 61,117 (2004).
Rate Design / Pricing		<u>Capacity Credit Market</u> - The Capacity Credit Market includes both the PJM Daily Capacity Credit Market and the PJM Monthly Capacity Credit Market. The former is a competitive market, administered by the OI in accordance with the provisions of its ELRP Schedule, for the purchase and sale of Capacity Credits for the business day following the day on which the market is conducted or for an intervening weekend day or holiday. The latter is a competitive market, administered by the OI in accordance with the provisions of its ELRP Schedule, for the purchase and sale of Capacity Credits for each or any of the twelve months following the month during which the market is conducted. ELRP, Schedule 11, Second Revised Sheet No. 198 *et seq.*; *id*. at 3.1, Second Revised Sheet No. 199.
SPP **Day-Ahead Market**	SPP is not currently operating a day-ahead market.	SPP does not currently operate energy markets. Interestingly, Exelon stated in its comments on SPP's RTO filing that it believed a day-ahead energy market should be implemented in conjunction with the proposed Financial Transmission Rights that SPP plans to implement (see below). In the RTO Order, the Commission did not directly respond to this comment or require that a day-ahead energy market be established at this time.
Real-Time Market/ Spot Market	SPP plans to implement a real-time energy balancing market in three increments, with final implementation to occur in October 2005. This real-time market will calculate nodal prices, based on submitted resource offers, and the procedures governing the market will include central dispatch instructions to resources to supply calculated imbalances.	SPP stated that it would have a real-time energy imbalance market in place by October 2005. According to their filing, this market would be implemented in three increments. In the first increment, infrastructure and procedures would be established to enable SPP to centrally calculate all imbalances within the SPP region. This infrastructure and set of procedures would also provide all the data necessary for after-the-fact settlement of energy imbalances. In the second increment, SPP would establish enhanced reliability systems and procedures, including the implementation of systems to supply data to control areas to ensure that those areas can operate reliably in conjunction with a real-time imbalance market. Finally, a real-time, offer-based energy market for calculating the price of imbalance energy would be implemented. This market will calculate nodal prices, based on the resource offers submitted, and will have procedures providing for

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	SPP is not currently operating any other real-time or spot markets.	central dispatch instructions to resources to supply the calculated imbalances. *See* SPP RTO filing, transmittal letter at 52, and Exhibit 10 (Testimony of Carl Monroe) at 6; *see also Southwest Power Pool, Inc.*, 106 FERC ¶ 61,110 (2004) (RTO Order) at P 117-120. In the RTO Order, the Commission accepted SPP's proposal for implementation of the energy imbalance market while recognizing that it is still a "work in progress." *RTO Order* at P 134.
Treatment of RMR Units	To date, SPP's treatment of RMR units or RMR policy has not been considered.	
Congestion Management	SPP's basic congestion management system includes the current redispatch procedures contained in its tariff, and the real-time energy imbalance market under development (described above.) Under SPP's current redispatch procedures, it receives price quotes from generators able to relieve a constraint, and then chooses economic alternatives to present to customers. SPP uses this process in conjunction with NERC's Transmission Loading Relief (TLR) process, as well as discounting to encourage counterflows. Once implemented, SPP plans to integrate the real-time energy imbalance market with its current congestion management procedures. SPP also plans to add financial transmission rights (FTRs) for market-based congestion management.	SPP's current redispatch procedures are found in Attachment K to its OATT. Under those procedures, when SPP receives a request for firm or network transmission service that is not fully available due to a transmission constraint, it assesses the ability of redispatch to relieve the constraint. Specifically, SPP determines the firm transmission reservations that, if curtailed, could relieve the constraint, and solicit from the holders of these reservations the price they would accept to relinquish their rights. SPP then determines the incremental cost of relieving the transmission constraint, and informs the potential customer of that cost. *See* SPP OATT, Attachment K. SPP states in its RTO filing that it uses these procedures along with NERC's TLR process and discounting to encourage counterflows. *See* Southwest Power Pool, Inc., 106 FERC ¶ 61,110 at P 116 (2004) (RTO Order). SPP plans to integrate these current procedures with the real-time energy balancing market (described above). SPP also informed the Commission in its RTO filing that after these procedures are integrated, it plans to add FTRs for market-based congestion management. In the RTO Order, the Commission accepted SPP's congestion management plans "as a reasonable initial approach to managing congestion," finding that it satisfies the requirements for Day 1 operation of an RTO. *Id.* at P 134. The Commission noted that it would address SPP's Day 2 plans for congestion management when the completed proposal is filed pursuant to section 205 of the FPA. *Id.* On rehearing, the Commission clarified that the RTO Order did not contemplate the development or implementation of Day 2 markets, beyond the energy imbalance market already in development as part of Phase 1 of the SPP plan, without the preparation of a cost/benefit analysis. *Southwest Power Pool, Inc.*, 109 FERC ¶ 61,010 at P 59 (2004).
Rate Design/Pricing	SPP currently has a zonal rate structure	SPP's zonal rate structure, which eliminated rate pancaking across the entire SPP

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	for all transmission service; rate pancaking within SPP has been eliminated.	footprint, was approved by the Commission in *Southwest Power Pool, Inc.*, 89 FERC ¶ 61,284 (1999). Under that structure, each member-system is its own zone. Schedules 7 and 8 of the SPP OATT determine which zonal rate will apply, based on where the generation source and load served is located. SPP did not propose any revisions to this rate structure when seeking RTO status. In the RTO Order, *Southwest Power Pool, Inc.*, 106 FERC ¶ 61,110 (2004), the Commission addressed concerns regarding the inclusion of more than one transmission owners' facilities in a single pricing zone, and the distribution of revenues by SPP in such situations. In that order, the Commission directed the parties to certain relevant precedent, and required SPP to submit a timetable for addressing the concerns. In its July 2 Order on Compliance Filing, the Commission has redirected SPP to submit the required timetable. *See Southwest Power Pool, Inc.*, 108 FERC ¶ 61,003 at P 80 (2004). Additionally, in its order on rehearing, the Commission denied a rehearing request urging the Commission direct SPP to adopt a single definition of transmission and an equitable methodology for allocating transmission revenues among multiple TOs located in a single pricing zone. *See Southwest Power Pool, Inc.*, 109 FERC ¶ 61,010 at P 51-52 (2004).

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CAISO **Reliability**	CAISO will meet planning and Operating Reserve criteria no less stringent than those established by Western Electricity Coordinating Council (WECC) and the North American Electric Reliability Council (NERC). CAISO prepares an annual forecast of weekly Generation capacity and weekly peak demand on the CAISO Controlled Grid. If the annual forecast shows that the applicable WECC/NERC Reliability Criteria cannot be met during peak load periods, CAISO will solicit bids for Replacement Reserves contracts of up to one (1) year, and load curtailment contracts. Replacement Reserves are dedicated to CAISO, and are capable of ramping at a specific load point within sixty (60) minute period, with output continuously maintained for a two hour period. Under CAISO's curtailment programs, an SC may specify loads that will be reduced at a specified Market Clearing Price. Supplemental Energy is from generating units bound by a Participating Generator Agreement (PGA), Participating Load	Under CAISO Tariff § 2.3.1.3, CAISO has Operational Control over the CAISO Controlled Grid in order to meet planning and Operating Reserve criteria no less stringent than those established by WECC and the North American Electric Reliability Council (NERC). On an annual basis CAISO prepares a forecast of weekly Generation capacity and weekly peak demand on the CAISO Controlled Grid. If the forecast shows that the applicable WECC/NERC Reliability Criteria cannot be met during peak load periods, then CAISO shall facilitate the development of market mechanisms to bring CAISO into compliance. CAISO will solicit bids for Replacement Reserves in the form of Ancillary Services, short-term generation supply contracts of up to one (1) year, and load curtailment contracts giving CAISO the right to reduce loads of those parties that win the contracts when there is insufficient generation capacity to satisfy those loads in addition to all other loads. CAISO Tariff § 2.3.5. Replacement Reserve - Replacement Reserves is generating capacity dedicated to CAISO, capable of starting up if not already operating, being synchronized to the CAISO Controlled Grid, and ramping at a specific load point within sixty (60) minute period, the output of which can be continuously maintained for a two hour period. Curtailment Programs - Under curtailment programs, an SC may specify loads that will be reduced at specified Market Clearing Prices or offer the right to exercise load curtailment to CAISO as an Ancillary Service or utilize load curtailment itself (by self provision of Ancillary Services) as Non-Spinning Reserve or Replacement Reserve. CAISO Tariff § 2.3.2.8. Supplemental Energy - Supplemental Energy is Energy from generating units bound by a Participating Generator Agreement (PGA), Participating Load Agreement, System Units and System Resources, which have uncommitted capacity following finalization of the Hour-Ahead Schedules and for which SCs have submitted bids to CAISO at least half an hour before commencement of the Settlement Period. CAISO Tariff § 2.5.22.4. RMR Generation - RMR Generation is generation CAISO determines is required to be on line to meet Applicable Reliability Criteria[10] requirements. By no later than one hour before the close of the Day-Ahead Market for the trading day, CAISO will notify

[10] Applicable Reliability Criteria means the reliability standards established by NERC, WECC and Local Reliability Criteria as amended from time to time, including any requirement by the NRC.

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	Agreement, System Units and System Resources, which has uncommitted capacity for which SCs have submitted bids to CAISO at least half an hour before commencement of the Settlement Period. RMR Generation is required to be on line to meet Applicable Reliability Criteria requirements.	SCs for Reliability Must-Run Units of the amount of Energy required from each RMR Unit in the trading day (RMR Dispatch Notice). The Energy to be delivered for each hour of the trading day pursuant to the RMR Dispatch Notice (including Energy the RMR Owner is entitled to substitute for Energy from the RMR Unit) is referred to as "RMR Energy." CAISO Tariff § 2.2.12.2.

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MISO **Reliability**	Midwest ISO customers may combine their requests for service in order to satisfy the minimum transmission capacity requirement. Curtailments in Midwest ISO are performed on a non-discriminatory. Curtailment applies equally to network and firm point-to-point service. Transmission providers may curtail non-firm point-to-point transmission service for reliability reasons when an emergency or other unforeseen condition threatens to impair or degrade reliability. The transmission provider shares curtailments among affected transmission owners or independent transmission companies, and the transmission customer, in proportion to their respective load ratio shares. The Midwest ISO must certify to the Commission the reliability and readiness of its systems 30 days before market startup.	<u>Capacity Requirements</u> **-** In applying for firm point-to-point transmission service, customers may combine their requests for service in order to satisfy the minimum transmission capacity requirement. Midwest ISO FERC Electric Tariff, Second Revised Volume No. 1, First Revised Sheet No. 80 (Effective January 1, 2003). In following procedures for network integration transmission service applications, applicants must include information, pursuant to regulations located in 18 C.F.R. § 220, including information regarding the amount and location of interruptible load included in network load. The applicant must include summer and winter capacity requirements for each interruptible load. Midwest ISO FERC Electric Tariff, Second Revised Volume No. 1, Original Sheet No. 116 (Effective April 1, 2002). <u>Curtailment rules and enforcement</u> **-** Curtailments are performed on a non-discriminatory basis to the transactions that effectively relieve the constraint. The transmission provider may utilize the transmission loading relief procedures available in Attachment Q. Curtailment will apply equally to network and firm point-to-point service. Non-firm service is subordinate to firm service. The transmission customer must curtail service upon request from the transmission provider. However, the transmission provider reserves the right to curtail any firm service, in whole or in part, when in its sole discretion it deems an emergency requires such curtailment. If a transmission customer fails to curtail service upon receiving a request to do so, the transmission customer may be subject to penalties, including: (1) $10 per kW for failure to curtail within 10 minutes; and (2) $20 per kW for failure to curtail within 20 minutes. The charges apply to the amount the customer failed to curtail. Midwest ISO FERC Electric Tariff, Second Revised Volume No. 1, First Revised Sheet No. 58 and 60 (Effective Dec. 23, 2002), and First Revised Sheet No. 59 (Effective January 1, 2003). The transmission provider reserves the right to curtail, in whole or in part, non-firm point-to-point transmission service for reliability reasons when an emergency or other unforeseen condition threatens to impair or degrade reliability. If a transmission customer fails to curtail service upon receiving a request to do so, the transmission customer may be subject to penalties, including: (1) $10 per kW for failure to curtail within 10 minutes; (2) $20 per kW for failure to curtail within 20 minutes; and (3) $20 per kW if the customer fails to interrupt service at the beginning of the clock hour for which service is requested, provided the customer is given a minimum of 40 minutes notice. The charges apply to the amount the customer failed to curtail. Midwest ISO FERC Electric Tariff, Second Revised Volume No. 1, First Revised Sheet No. 70 (Effective December 23, 2002), Original Sheet No. 71 and 72, First Revised Sheet No.

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		73 (Effective April 1, 2002), and First Revised Sheet No. 59 (Effective December 23, 2002). For Network Service, prior to the commencement of service date, the transmission provider, in coordination with the transmission owner or independent transmission company and the transmission customer, establish load shedding and curtailment procedures pursuant to the Network Operating Agreement. Midwest ISO FERC Electric Tariff, Second Revised Volume No. 1, First Revised Sheet No. 132 (Effective Dec. 23, 2002). The transmission provider shall share curtailments among the affected transmission owners or independent transmission companies, and the transmission customer, in proportion to their respective load ratio shares. Midwest ISO FERC Electric Tariff, Second Revised Volume No. 1, First Revised Sheet No. 134 (Effective December 23, 2002). The Midwest ISO must certify to the Commission, 30 days before market startup, the reliability and readiness of its systems. The Midwest ISO must file its independently evaluated Verification Plan with the Commission at least three months prior to the market startup. *See* 108 FERC ¶ 61,163 (2004).
NYISO **Reliability**	NYISO requires that both suppliers (*i.e.*, generators) and loads (*i.e.*, customers) meet minimum reliability standards. NYISO requires generators, suppliers and loads to exchange certain operating and reliability data with the ISO and the Transmission Owners'	NYISO requires that both suppliers (*i.e.*, generators) and loads (*i.e.*, customers) meet minimum reliability standards. Entities that are located within the control area must accept and comply with control area standards with respect to system design, equipment ratings, operating practices and maintenance practices as set forth in the ISO Procedures so that sufficient electrical equipment control capability, information and communication are available to the ISO for planning and operation of the NYCA. Its facilities must be able to respond to command and control instructions from the ISO. It must have compatible operational communication mechanisms, maintained at its

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	NYISO's UCAP – (the measure by which installed capacity suppliers will be rated) represents a minimum level of Unforced Capacity that must be secured by LSEs in the control area. NYISO determines the amount of Unforced Capacity that must be sited within the control area To preserve system reliability, the ISO must ensure that there will be sufficient resources available to meet forecasted Load and reserve requirements over the seven-day period NYISO offers additional reliability programs that are related to demand response and curtailment.	expense, to interact with the ISO. It must ensure the continued compatibility of its local energy management system, system monitoring and telecommunications systems to satisfy the technical requirements of interacting with the ISO as the ISO directs the operation of the control area. NYISO requires generators, suppliers and loads to exchange certain operating and reliability data with the ISO and the Transmission Owners' Control Centers in accordance with the ISO Agreement and the ISO/TO Agreement, applicable ISO operating and reliability requirements, and in conjunction with any requirements for interconnection with the Transmission Owner. NYISO's Minimum Unforced Capacity Requirement (UCAP – the measure by which installed capacity suppliers will be rated) represents a minimum level of Unforced Capacity that must be secured by LSEs in the control area for each Obligation Procurement Period. Under the provisions of the Services Tariff and the ISO Procedures, each LSE will be obligated to procure its LSE Unforced Capacity Obligation. The LSE Unforced Capacity Obligation will be determined for each Obligation Procurement Period by the ICAP Spot Market Auction, in accordance with ISO Procedures. Qualified Resources will have the opportunity to supply amounts of Unforced Capacity to meet the LSE Unforced Capacity Obligation as established by the ICAP Spot Market Auction. NYISO determines the amount of Unforced Capacity that must be sited within the control area, and within each Locality, and the amount of Unforced Capacity that may be procured from areas outside of the control area, in a manner consistent with its Reliability Rules. <u>See</u> Article 5 (Control Area Services: Rights and Obligations) and Attachment G (Emergency Demand Response Program) of NYISO's Market Administration and Control Area Service Tariff. <u>Reliability Forecasts</u> - To preserve system reliability, the ISO must ensure that there will be sufficient resources available to meet forecasted Load and reserve requirements over the seven-day period that begins with the next Dispatch Day. The ISO will perform a Supplemental Resource Evaluation (SRE) for days two through seven of the commitment cycle. If it is determined that a long start-up time Generator is needed for reliability, the ISO shall accept a Bid from the Generator and the Generator will begin its start-up sequence. *See* Article 4.10 (Reliability Forecasts) of NYISO's Market Administration and Control Area Service Tariff. NYISO has established the following Operating Reserves in accordance with the ISO

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		Procedures and the Reliability Rules: (1) Spinning Reserve (10-Minute Synchronized Reserve); (ii) 10-Minute Non-Synchronized Reserve; and (iii) 30- Minute Reserve. The ISO shall maintain Operating Reserves in accordance with the ISO Procedures and the Reliability Rules. NYISO also is required to develop and periodically review a Black Start restoration plan for the NYS Power System. NYISO may amend this restoration plan and determine Black Start requirements to account for changes in system configuration if the ISO determines that additional Black Start resources are needed. See Schedule 5 (Operating Reserve Service) and Schedule 6 (Black Start Service) of NYISO's OATT. Finally**,** NYISO offers additional reliability programs that are related to demand response and curtailment.
ISO-NE **Reliability**	There are two separate capacity requirement periods, as calculated in section 8.1 of Market Rule 1. ISO-NE assigns capacity obligations at the beginning of the year, to be updated monthly with load shifting. Participants must show that they have met the capacity requirement to avoid a deficiency auction. Unforced capacity can be curtailed below the ICAP Equivalent. ISO-NE purchases in advance capability to satisfy the expected 10-minute non-synchronous and 30-minute Operating Reserve requirements. ISO-NE checks for deficient Participants monthly, and subjects them to auctions and a deficiency fee. External Transactions are curtailed on a	There are two separate capacity requirement periods: the Summer Capability Period and the Winter Capability Period. Each Period's capacity requirement is calculated at the beginning of the Capability Year. If NEPOOL is unable to determine the capacity requirements three months prior to the start of the Capability Year, the capacity requirements are determined by ISO-NE in consultation with the NEPOOL Participants. The NEPOOL Unforced Capacity Requirement for the two periods equals the Installed Capacity Requirement times the quantity one minus the system-wide weighted average equivalent forced outage rate of the generating assets located within the NEPOOL Control Area. NEPOOL Market Rule 1, section 8.1, Original Sheet No. 79. ISO-NE assigns each Participant an Unforced Capacity obligation prior to the beginning of the Capability Year and updates this allocation monthly throughout the Capability Year as customers are gained and lost through load shifting. Each Participant's monthly requirement equals the product of: (i) the Summer Capability Period or Winter Capability Period Unforced Capacity Requirement for the Obligation Month; and (ii) the Participant's pro-rata share of the sum of all Participant annual coincident contributions to the NEPOOL annual peak load from the calendar year immediately prior to the Capability Year. NEPOOL Market Rule 1, section 8.2.1, 1st Revised Sheet No. 80. Each Participant must obtain Capacity Credits or procure Unforced Capacity in an amount equal to its Capacity obligation, from any ICAP Resource through bilateral transactions and/or purchases in ISO-administered installed capacity auctions. Each Participant must demonstrate that it has obtained a sufficient amount of Unforced Capacity prior to the beginning of each Obligation Month. Participants that fail to

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	pro-rata basis. In external Interfaces without physical reservations, curtailment occurs in economic merit order. In external interfaces without physical reservations, curtailments occur by transmission priority of the associated transmission reservation. Participants and Transmission Customers are charged for Congestion Costs. Firm and Non-Firm Internal Point-to-Point Service are curtailed based on economic merit order. ISO establishes Curtailment procedures prior to the service commencement date for Network Service. Curtailment must be shared by the customers taking Internal Point-to-Point Service, MTF Service and/or Through or Out Service and Network Customers.	make timely submissions of the above information are subject to a Deficiency Auction. NEPOOL Market Rule 1, section 8.2.2, 1st Revised Sheet No. 80. Any Unforced Capacity that is not out of service or scheduled in the Day-Ahead Market may be scheduled to supply energy for use in External Transactions subject to curtailment within the hour. Curtailment cannot exceed the ICAP Equivalent committed to the NEPOOL Control Area. If an ICAP Resource's External Transaction is curtailed in-hour, the Participant scheduling such transaction is paid the Real-Time generator nodal price for the remainder of the hour. New England only recalls External Transactions associated with a non-ICAP Resource due to unavailability of the resource backing that transaction, or in a system emergency. NEPOOL Market Rule 1, section 8.3.9, 1st Revised Sheet. No. 89. ISO-NE conducts an advance purchase of capability to satisfy the expected 10-minute non-synchronous and 30-minute Operating Reserve requirements. If ISO-NE expects to hold Replacement Reserve over the 30-minute Operating Reserve Requirement and above efficiencies available to the Control Area, that amount of Replacement Reserve will be added to the 30-minute requirement in the Forward Reserve Auction. NEPOOL Market Rule 1, section 9.1, Original Sheet No. 94. At the conclusion of each month, ISO-NE determines whether each Participant has satisfied its ICAP Responsibility obligation for the month. Deficient Participants must purchase Kilowatts of surplus ICAP equal to the amount of its deficiency, and must pay to NEPOOL for the month any applicable fees for services assessed plus the product of its total Kilowatts of deficiency and the ICAP deficiency charge. The ICAP deficiency charge is then divided between Participants who met or exceeded their ICAP obligations. Restated NEPOOL Agreement, section 12.5, Original Sheet No. 154. <u>Curtailment Rules for External Transactions</u> - In the event that the transfer limit for a given external interface does not allow all Excepted Transactions submitted over that interface to flow, they are curtailed on a pro-rata basis. NEPOOL Tariff, section 25D(a), 1st Revised Sheet No. 84. For external Interfaces where advance physical reservations are not required, curtailment of External Transactions is based on economic merit order. NEPOOL Tariff, section 25D(b), 2nd Revised Sheet No. 85. For external interfaces where advance physical reservations are required, curtailments resulting from a reduction in total transfer capability are based on transmission priority

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		of the associated MTF or Non-PTF transmission reservation. In the event of a tie within a category of transmission service, (a) transactions within a given sub-category of non-firm transmission service is curtailed on the basis of Real-Time Energy Market timestamp order, and (b) transactions with firm transmission service is curtailed on a pro-rata basis. NEPOOL Tariff, section 25D(d), 1st Revised Sheet No. 86. The System Operator redispatches all Resources in order to meet load and to accommodate External Transactions. Participants and Transmission Customers are charged for the Congestion Cost and any other costs associated with such redispatch. If the System Operator exercises its right to affect a Curtailment of Through or Out Service or Internal Point-to-Point Transmission Service or MTF Service, no credit or other adjustment is provided as a result of the Curtailment with respect to the charge payable by the customer. NEPOOL Tariff, section 25D(j), 1st Revised Sheet No. 88. <u>Curtailment of Firm Transmission Service</u> - Resources within the NEPOOL Control Area using Firm Internal Point-to-Point Service is curtailed based on economic merit order and has no physical scheduling or dispatch rights. NEPOOL Tariff, section 27.6, 3rd Revised Sheet No. 97. <u>Curtailment of Non-Firm Internal Point-to-Point Service and Non-Firm MTF Service</u> - Resources within the NEPOOL Control Area using Non-Firm Internal Point-to-Point Service is curtailed based on economic merit order and has no physical scheduling or dispatch rights. NEPOOL Tariff, section 28.7, 4th Revised Sheet No. 109. <u>Curtailment of Network Service</u> - The System Operator must establish Curtailment procedures prior to the service commencement date. To the extent the System Operator determines that the reliability of the System can be maintained by redispatching resources, the System Operator initiates procedures as dictated by the Network Operating Agreement to redispatch all the Network Customer's resources and the Participants' own resources on a least-cost basis without regard to the ownership of such resources. The Non-Participant Transmission Customers and Participants bear the costs associated with such redispatch. Any Curtailment must be shared by the customers taking Internal Point-to-Point Service, MTF Service and/or Through or Out Service and Network Customers on a non-discriminatory basis. NEPOOL Tariff, section 45, 1st Revised Sheet Nos. 172-174. The System Operator reserves the right to effect a Curtailment of Network Integration Transmission Service without liability on the part of the System Operator or the Participants for the purpose of making necessary adjustments to, changes in, or repairs on the Participants' lines, substations and facilities, and in cases where the continuance

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		of Network Integration Transmission Service would endanger persons or property. In the event of any adverse condition or disturbance on the PTF or on any other system directly or indirectly interconnected with the PTF, the System Operator may effect a Curtailment of Network Integration Transmission Service in order to: (i) limit the extent or damage of the adverse condition or disturbance; (ii) prevent damage to generating or transmission facilities; or (iii) expedite restoration of service. The Network Operating Agreement specifies the rate treatment and all related terms and conditions applicable in the event that the Network Customer fails to respond to established Load Shedding and Curtailment procedures. NEPOOL Tariff, section 45.7, 3rd Revised Sheet No. 174A.
PJM **Reliability**	PJM's capacity obligation formulas calculate the Daily Available Capacity Obligation (DACO), the Installed Capacity (ICAP) Obligation, as well as the Daily Available Capacity. PJM's Reserve Margin Requirements, for both operating and spinning reserves, are set out in detail in PJM's Reserve Requirements Manual (No. 20). Billing information for the cost of operating and spinning reserves is found in PJM's Operating Agreement.	<u>Capacity Requirements</u> - Daily Available Capacity Obligation (DACO) formulas: <u>DACO</u>. The DACO for each Load Serving Entity (LSE) is 106 percent of the total day-ahead estimated load requirement coincident with the Zone peak for the LSE in the PJM West Region as calculated by each of the PJM Zonal Entities. This forecast is based upon industry-accepted load forecasting methodologies for individual customers or groups of customers: DACO = the Daily Load Estimate (DLE)[11] x 1.06. *See* http://www.pjm.com/contributions/pjm-manuals/pdf/m17v2.pdf (PJM Manual: Capacity Obligations). <u>Installed Capacity (ICAP) Obligation</u> - The ICAP obligation is equal to an LSE's share of the Forecast Period Peak Load plus reserves: ICAP Obligation = FPPL[12] Share[13] x (1 + Installed Reserve Margin in percent (IRM)). *See* http://www.pjm.com/contributions/pjm-manuals/pdf/m17v2.pdf (PJM Manual: Capacity Obligations). <u>Expected Peak</u> – PJM West peak load level (megawatts) that has equal probability of

[11] DLE for each Load Serving Entity (LSE) as provided by the appropriate Zone Entity capped at 106 percent of the Forecast Period Peak Load (FPPL).

[12] FPPL means a forecast of the peak load for each Zone in the PJM West Region as prepared by PJM for each Forecast Period, with such forecast based on a ninety percent probability that such peak shall not be exceeded.

[13] FPPL Share means the Forecast Period Peak Load for each LSE as provided by the Zone Entity prior to the beginning of an interval.

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		being met or being exceeded. *See* http://www.pjm.com/ contributions/pjm-manuals/pdf/m17v2.pdf (PJM Manual: Capacity Obligations).
SPP **Reliability**	Pursuant to the Revised Membership Agreement, SPP is to conform to applicable reliability criteria, policies, standards, rules, regulations, guidelines and other requirements of both SPP and NERC, as well as the specific reliability requirements of Transmission Owners and any requirements of State and Federal regulatory authorities. Under the Revised Membership Agreement, SPP is the Reliability Coordinator, and must approve all planned maintenance and expansion of the transmission system and coordinate maintenance of generating units to the extent such maintenance could affect the capacity or reliability of the system. As NERC Reliability Coordinator, SPP may order redispatch of generation if necessary. SPP has exclusive authority for determining available transmission capacity (ATC). The Commission has approved, on an interim basis, an unexecuted Joint Operating Agreement (JOA) between the Midwest ISO (MISO) and SPP, and required SPP must to file, by December 1, 2004, a revised JOA that is executed by both parties.	The Revised Membership Agreement includes several provisions regarding SPP's responsibility for reliability. Section 2.1.1(b) of that agreement generally states: > SPP shall function in accordance with Good Utility Practice and shall conform to applicable reliability criteria, policies, standards, rules, regulations, guidelines and requirements of SPP and NERC, Transmission Owner's specific reliability requirements and operating guidelines (to the extent these are not inconsistent with other requirements specified in this paragraph), and all applicable requirements of federal and state regulatory authorities. Additionally, SPP reviews and approves all requests for service, schedules transmission transactions, schedules maintenance of the transmission system, coordinates maintenance of generation where such maintenance could impact reliability, and determines ATC. Revised Membership Agreement at § 2.1.1. Furthermore, section 2.1.2 of the Revised Membership Agreement establishes SPP as the Reliability Coordinator of the transmission system, and gives it monitoring and emergency response responsibilities. Additionally, that section gives SPP the power to redispatch generation for reliability purposes. In its RTO filing, SPP also stated that it would continue to act to ensure the integration of reliability practices within the interconnection and among regions. *See* SPP's RTO filing, transmittal letter at 57-58. In the RTO Order, the Commission found that SPP met Order 2000's requirements for Short-Term Reliability. *Southwest Power Pool, Inc.*, 106 FERC ¶ 61,110 (2004) (RTO Order) at P 90. In response to a concern raised by the New Mexico Attorney General regarding SPP serving as both RTO and reliability organization, the Commission stated that it would take the matter into consideration, but would not require separation at this time. *Id.* at P 91. With regard to interregional coordination, the Commission directed SPP, in both the RTO Order and its July 2, 2004 Order on Compliance Filing, to develop and file a seams agreement with MISO. *Id*. at P 201. In response to this direction, SPP filed an unexecuted, proposed Joint Operating Agreement (SPP JOA) with MISO on August 2, 2004.

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		As filed, the SPP JOA contains all the provisions necessary for Phase 0, or non-market to non-market operations, and some provisions addressing Phase 1, or market-to-non-market operations, including provisions regarding coordination issues. Generally, the SPP JOA covers exchange of data, calculation of available transmission capacity and available flowgate capacity, and coordination of outages, expansion, scheduling and voltage control and reactive power. The Commission accepted the SPP JOA on an interim basis, for non-market-to-non-market operations prior to the start-up of MISO markets on March 1, 2005. *Southwest Power Pool, Inc.*, 109 FERC ¶ 61,008 (2004). The Commission rejected, however, application of the SPP JOA after market operations being in MISO, finding that it did not cover "critical market-to-non-market elements," including flowgate coordination provisions and the congestion management process. *Id.* at P 31. The Commission directed SPP to file, by December 1, 2004, either: (1) a revised JOA that is executed by SPP and MISO, and addresses market-non-market issues, including a Congestion Management Process and coordinated flowgates; or (2) the draft JOA included in MISO's protest, executed by SPP and MISO. *Id.* at P 33.

Treatment of Existing Contracts
Issue # 7

Organization	Summary	Research
CAISO **Treatment of Existing Contracts**	Participating TOs and holders of transmission rights under an Existing Contract will work with CAISO must develop operational protocols which allow existing contractual rights to be exercised. The rights and obligations of Non-Participating TOs under existing contracts will continue to be honored for the duration of those contracts.	Under CAISO Tariff § 2.4.3, each Participating TO and holder of transmission rights under an Existing Contract will work with CAISO to develop operational protocols which allow existing contractual rights to be exercised. The rights and obligations of Non-Participating TOs under existing contracts will continue to be honored by the parties to those contacts, for the duration of those contracts (CAISO Tariff § 2.4.4.1.1).
MISO **Treatment of Existing Contracts**	Under the TEMT, 229 GFAs have been examined. The 229 GFAs account for 24,803 Mw or 23.06 percent of MISOs total load. Of those 229 GFAs, 51 have settled and selected service under the MISO TEMT; 51 did not settle, were found governed by the just & reasonable standard of review, and required to select an option for service under the MISO TEMT and; 127 GFAs did not settle but were carved out of the MISO TEMP because the agreement was governed by the Mobile-Sierra standard of review, was silent on the standard of review, or was considered non-jursidictional. Transmission-owning members must take transmission service under the Midwest ISO Tariff. Transmission owners and ITCs with	On March 31, 2004, MISO filed a proposed Open Access Transmission and Energy Markets Tariff (TEMT) with the Commission. As a result of that filing, the Commission examined over 200 grandfathered agreements (GFAs) in order to determine how these GFAs will fit into and affect the proposed Day 2 Markets. The Commission reviewed 229 GFAs which covered 24,000 Mw of capacity. The GFAs that settled before the end of the Commission's hearing proceedings were permitted to select one of 3 options for service under MISO's tariff. Of those 229, 51 GFAs settled before the end of the hearing procedures with 5 converting or already covered under the TEMT, 14 selecting option A for service under MISO, 29 selecting option B for service under MISO and 3 selecting a combination of options A and B for service under MISO. The Commission carved out 32 non-jurisdictional GFAs, 81 GFAs found to be governed by Mobile-Sierra, and 14 GFAs that were silent as to the standard of review that governed. Of the remaining GFAs that did not settle, 51 were found to be just and reasonable and were required to select one of the proposed options for scheduling and service under the MISO tariff. The GFAs that settled before the end of the hearing proceedings accounted for 9,708 Mw or 9.3 percent of MISO's total load, the GFAs that did not settle but were found just and reasonable accounted for 5,132 Mw or 4.77 percent of MISO's total load, and the GFAs that did not settle and were carved out accounted for 9,962 MW or 9.26 percent of MISO's total load. Aspects of this issue are currently on rehearing before the Commission and will be decided in the future. *See* 108 FERC ¶ 61,236 (2004). Transmission-owning members must take transmission service under the Midwest ISO

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	grandfathered agreements are not required to pay charges under Schedules 1 through 9 of the Tariff. Where grandfathered agreements do not cover ancillary services or losses, the services will be provided pursuant to the Midwest ISO Tariff Schedules and Attachment M.	Tariff for their use of the Midwest ISO transmission system to serve bundled load and grandfathered agreement customers. These transmission-owning members will be exempt, during the transition period, from rates under the Midwest ISO Tariff for services provided pursuant to the existing agreements, except the Cost Adder, which will reimburse Midwest ISO for the services it performs that benefit all users of the grid. *See Midwest ISO*, 103 FERC ¶ 61,038 (2003) (Order on Reconsideration and Compliance and Ordering Further Compliance Filing). As part of the limitations on charges and cost responsibilities within Midwest ISO, for service provided pursuant to grandfathered agreements inside Midwest ISO, transmission owners and independent transmission companies (ITC) are not required to pay charges under Schedules 1 through 9 of the Tariff. Nor are they responsible for losses under Attachment M. Each transmission owner or ITC with grandfathered contracts may remains responsible for charges under Schedule 10 to the extent that they take service under that portion of the Tariff. Midwest ISO FERC Electric Tariff, Second Revised Volume No. 1, Second Revised Sheet No. 143 (Effective June 7, 2003), Original Sheet No. 143A (Effective June 7, 2003). Grandfathered agreements for load outside Midwest ISO are exempt from Schedules 1 through 9, but must pay the transmission provider for services under Schedule 10. Midwest ISO FERC Electric Tariff, Second Revised Volume No. 1, Second Revised Sheet No. 144 (Effective June 7, 2003). Where grandfathered agreements do not cover ancillary services or losses, the services will be provided pursuant to the Midwest ISO Tariff Schedules and Attachment M, respectively. Midwest ISO FERC Electric Tariff, Second Revised Volume No. 1, Second Revised Sheet No. 143 (Effective April 1, 2002, filed pursuant to order of the Commission in 103 FERC ¶ 61,038).
NYISO **Treatment of Existing Contracts**	Existing firm service customers (wholesale requirements and transmission-only, with a contract term of extending beyond the ISO implementation date), have the right to take Transmission Service from the ISO.	Existing firm service customers (wholesale requirements and transmission-only, with a contract term of extending beyond the ISO implementation date), have the right to take Transmission Service from the ISO in accordance with the provisions of Attachment K. This transmission reservation priority is independent of whether the existing customer continues to purchase Capacity and Energy from a Transmission Owner or elects to purchase Capacity and Energy from another Supplier. At the end of the contract terms, all NYS Transmission System capacity associated with Grandfathered Rights and/or TCCs shall be offered for sale as TCCs in the next TCC auction facilitated by the ISO. *See* Attachment K (Reservation of Certain Transmission Capacity and LMBP Transition Period) and Attachment L (Existing Transmission Agreements and Existing

Organization	Summary	Research
		Transmission Capacity for Native Load Tables) of NYISO's OATT.
ISO-NE **Treatment of Existing Contracts**	ISO-NE has several grandfathered contracts in its tariff.	ISO-NE has several grandfathered contracts in its tariff. The entire list of contracts, which continue to be in effect at the rates and terms within the contracts rather than the tariff, are listed in: NEPOOL Tariff, Attachment G, 3rd Revised Sheet No. 271; NEPOOL Tariff, Attachment G-1, 2nd Revised Sheet No. 277; and NEPOOL Tariff, Attachment G-2, 2nd Revised Sheet No. 278.
PJM **Treatment of Existing Contracts**	PJM's Operating Agreement does not conflict with members' existing contracts but rather makes adjustments for prior contractual obligations.	The Operating Agreement does not conflict with any contract or other agreement or instrument to which a Member is bound. OA, 17.1.5. Consistent with existing contracts, all Market Participants comply with all directions from the OI for the purpose of managing, alleviating, or ending an emergency. OA, Schedule 1, 1.7.11. Metering of energy – the integration of megawatt hours in the clock hour – is adjusted for other contractual obligations of any Member and for transmission losses. OA, 14.3. Existing contractual obligations may not preclude participation in the Emergency LRP, but may require special consideration such that appropriate settlements are made within the confines of the existing contract. ELRP, Registration, Original Sheets Nos. 146 & 159.End-use customers that have LMP-based contracts under which they have agreed to pay their LSE for the physical delivery of energy according to the hourly value of the real-time LMP as calculated by PJM may participate in the real-time market. Economic LRP, Participant Qualifications.
SPP **Treatment of Existing Contracts**	SPP proposed to maintain 417 grandfathered agreements. The Commission allowed SPP to maintain these agreements, but required it to provide a schedule for converting the agreements to the SPP OATT. To date, SPP has committed to hold a technical workshop on GFA conversation, to initiate discussions with the GFA parties to explore renegotiation or conversion to OATT service.	In its RTO filing, SPP proposed to maintain 417 grandfathered agreements. These agreements include long-term firm transmission service agreements executed prior to April 1, 1999 and network integration service agreements executed prior to February 1, 2000. Also included are bundled wholesale contracts which reserve transmission as part of the contract. SPP argued in its RTO application that the issue of maintaining existing contracts is considered a "Day 2" compliance matter and that Order No. 2000 allows time beyond initial start-up to deal with such issues. SPP also stated that its Regional Tariff Working Group was considering subjecting grandfathered load to the Scheduling and Tariff Administration Fee provided in Schedule 1 of the SPP OATT. *See Southwest Power Pool, Inc.*, 106 FERC ¶ 61,110 (2004) (RTO Order) at P 99. In the RTO Order, the Commission stated that treatment of existing contracts would be reviewed on an RTO-by-RTO basis, and that it recognized the difficult issues presented by existing agreements. *Id.* at P 106-107. The Commission encouraged transmission customers with grandfathered contracts to convert to direct service under the SPP

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		OATT, but did not require such conversion. *Id*. at P 108. Consistent with Order No. 2000-A, however, the Commission did require that Transmission Owners, on behalf of their entire load, including grandfathered wholesale and bundled retail loads, take service under the non-rate terms and conditions in the SPP OATT as a prerequisite to obtaining RTO status from the Commission. *Id*. Additionally, the Commission directed SPP to submit a compliance filing disclosing the amount of load covered by the grandfathered agreements, and the percentage of total load that amount represents. *Id*. at P 110. Also, SPP was directed to submit a schedule for converting the grandfathered contracts to the OATT, "consistent with the guidance provided to Midwest ISO, to facilitate market operations." *Id*. In compliance with the RTO Order, SPP stated that revised section 39 of its OATT provides that each Transmission Owner not otherwise taking network integration transmission service under SPP's OATT is subject to the non-rate terms and conditions of the OATT for bundled retail load, including bundled load under GFAs. Additionally, SPP stated that section 39 identifies the specific non-rate terms and conditions that would apply to bundled and grandfathered load. Further, SPP submitted a proposed Attachment W to its OATT, which was intended to identify all currently effective grandfathered agreements. SPP also reported that over 90 percent of its load is subject to at least the non-rate terms and conditions of the SPP OATT, and that it expected conversion of the grandfathered load to the OATT would occur in accordance with the individual terms of each GFA and the current OATT. The Commission found that SPP substantially complied with the direction in the RTO regarding placing all load under its OATT. The Commission noted, however, that "it is appropriate that all load be made subject to the non-rate terms and conditions of the OATT, in order to ensure that non-discriminatory service is provided thereunder." *Southwest Power Pool, Inc.*, 108 FERC ¶ 61,003 at P 75 (2004). Further, the Commission held that SPP had not complied with the requirement to disclose the magnitude of its grandfathered load and provide a schedule for converting the grandfathered agreements (GFAs) to OATT service, and required SPP to submit a further compliance filing. In compliance with the July 2 Order on Compliance Filing, SPP provided an explanation of all currently effective GFAs. In its explanation, SPP asserted that there is approximately 6,200 MW of capacity associated with the GFAs for which it has data, and that it believes that the actual total for all currently effective GFAs is 7,000 to 8,000 MW. This total would represent 20 to 25 percent of SPP's load. Further, SPP reiterated that the GFAs are scheduled to terminate in accordance with their terms, and

Organization	Summary	Research
		that it would work with members to pursue conversion of the contracts to OATT service. SPP committed to hold a technical workshop on conversion issues, and then initiate discussions with each of the GFA parties to explore renegotiation or termination of the contracts. SPP stated that it would report to the Commission on its progress within six months following the commencement of RTO operations. The Commission accepted these commitments in its October 1, 2004 Order on Compliance Filing. *Southwest Power Pool, Inc.*, 109 FERC ¶ 61,009 at P 48 (2004).

Reporting Requirements
Issue # 8

Organization	Summary	Research
CAISO	None, other than the MMIPs which set forth the information dissemination CAISO generally undertakes.	None, other than the MMIPs which set forth the information dissemination, publication and reporting activities that CAISO generally undertakes to meet its reporting requirements to regulatory agencies, Market Participants and others. MMIP 1.1.2.
MISO	Should the split of control area functions in Midwest ISO create competitive or reliability problems, Midwest ISO must report this problem to the Commission and other authorities. Midwest ISO must report, within one year of the start of Day-2 operations, an assessment of any efficiency and independence issues created by the continuation of the 40 Control Area structure. Midwest ISO must file an informational update on progress toward a centralized, bid-based dispatch market. Midwest ISO was required to submit an implementation plan for achieving a common market within 45 days of the Commission's 7/31/02 order, with frequent progress reports thereafter, every 60 days. Midwest ISO was directed to submit periodic informational filings concerning implementation costs for development of its Day-2 market.	Although the Midwest ISO Agreement commits to assessing the relationship between control areas and Midwest ISO in an 18-month assessment report, we will also require this relationship to be monitored on an ongoing basis. If the ongoing monitoring program determines that the split of functions creates a competitive or reliability problem that affects the ISO's ability to provide reliable, non-discriminatory transmission service, which the ISO cannot resolve, the ISO must report this problem immediately to the Commission and other appropriate regulatory authorities. The ISO should also recommend cost effective solutions. *Midwest ISO, et al*., 84 FERC ¶ 61,231 at 62,159 (1998) (September 16 Order), *order on reh'g*, 85 FERC ¶ 61,372 (1998). We expect Midwest ISO to update its information in the later report, in which they will file, within one year of the start of Day-2 operations, an assessment of any efficiency and independence issues created by the continuation of the 40 Control Area structure, an analysis of merging control area functions in part or all of Midwest ISO, a recommendation for consolidating Control Areas, and the timeframe for such operational integration, should the analysis support such an outcome. *Midwest ISO*, 102 FERC ¶ 61,196. (This requirement replaced the above requirement in the September 16 Order.) In light of the August 14, 2003 blackout, ongoing disagreements about control area responsibilities, and a proposed Reliability Charter to be developed by Midwest ISO, the Commission determined that Midwest ISO must have the ability to direct the actions of control areas through financially binding LMPs along with penalties for excessive deviations from dispatch instructions, to successfully and reliably operate a centralized, bid-based dispatch market. The Commission advised Midwest ISO to state clearly which functions must be under its exclusive direction to ensure that reliability is maintained. The Commission also directed Midwest ISO to file, within three months of the date of the order, an informational update on progress. *Midwest ISO*, 105 FERC ¶ 61,145 (2003) (October 29 Order).

Organization	Summary	Research
		On July 31, 2002, the Commission conditionally accepted the Alliance Companies' compliance filings indicating which RTO (PJM or Midwest ISO) they chose to join, subject to satisfactory compliance with certain conditions, including that a single market across the two RTOs must be implemented by October 1, 2004, an implementation plan for achieving a common market by October 1, 2004 must be provided within 45 days of the July 31 Order, and frequent progress reports must be provided thereafter. *Alliance Companies, et al.*, 100 FERC ¶ 61,137 (2002) (*Alliance II*). In development of the Midwest market and with respect to implementation costs, the Commission permitted Midwest ISO to recover its prudently-incurred costs, as supported by an initial report and subsequent informational filings. Therefore, Midwest ISO was directed to submit periodic informational filings until these services commence. In the first informational filing, the Midwest ISO was directed to explain: (1) alternative methods of developing these services considered; (2) progress made in developing these services; (3) actions that it will take to establish these services; and (4) a detailed breakdown of the total start-up costs. For administrative convenience, Midwest ISO was directed to submit the first informational filing no later than 30 days from the date of issuance of the order. *Midwest ISO*, 101 FERC ¶ 61,221 (2002).
NYISO	NYISO is required to make semi-annual reports to the Commission.	Pursuant to the Commission's directive in 97 FERC ¶ 61,095, beginning in December 2001 and semi-annually in June and December of each year thereafter, NYISO is required to submit a report to the Commission regarding: (i) its existing demand response programs, the status of real-time demand response mechanisms, and the effects of demand response programs on wholesale prices; and (ii) the addition of new generation resources in the New York Control Area. Additionally, pursuant to Article 4.1 "Informational and Reporting Requirements" of NYISO's *Market Administration and Control Areas Service Tariff*, NYISO states that it shall operate and maintain an OASIS, including a Bid/Post System that will facilitated the posting of bids to supply energy, ancillary services and demand reductions by suppliers for use by the ISO an the posting of LMP prices and schedules for accepted bids.
ISO-NE	ISO-NE is required to submit quarterly and annual reports to the Commission.	The ISO is required to submit quarterly reports and annual state of the market reports to the Commission. NEPOOL Market Rule 1, Appendix A, Section 11. ISO-NE is to include in its quarterly reports to the Commission information regarding all instances of

Organization	Summary	Research
		mitigation of pivotal suppliers and also include in its annual reports an assessment of its market design. ISO New England Inc. 104 FERC ¶ 61,039 (2003).
PJM	Reporting requirements are considered separately for PJM's Office of the Interconnect and the RTO itself.	Office of the Interconnect - OI produces special reports reasonably requested by Members Committee. OA, Schedule 1, 1.6.3. OI reports the planned schedule for a hydropower resource to the operator of that resource as necessary for plant safety and security, and legal limitations on pond elevations. OA, Schedule 1, 1.10.8(a). OI reports to Market Participants results of its evaluation of the procedures for the determination of Locational Marginal Prices, as well as procedures for determining and allocating Financial Transmission Rights and associated Transmission Congestions Charges and Credits, not less often than every two years. OA, Schedule 1, 2.7. OI files with FERC a report that identifies economic expansion or enhancement, estimated cost, entity(ies) that will be responsible for constructing and owning or financing the project, and market participants designated to bear responsibility for the costs of the project. ELRP, Schedule 6, 1.6. In the event that Transmission Owner declines to construct an economic transmission enhancement or expansion developed under Sections 1.5.6(d) and 1.5.7 of Schedule 6 that such Transmission Owner is designated by the Regional Transmission Expansion Plan to construct (in whole or in part), the OI will promptly file with the FERC a report on the results of the pertinent economic planning process in order to permit FERC to determine what action, if any, it should take. OA, Schedule 6, 1.7(d). OI does not disclose commercially sensitive or proprietary information in any repot or web site posting. Schedule 11, 4.2. PJM reports to the Commission: (1) names of those end-use customers who indicated that distributed generation would be run in support of the load reduction program to the EPA, together with the permitting information that was supplied upon registration; and (2) annually, a summary of the status of the program, having first sent it to the Board, Members Committee, Reliability Committee, Energy Market Committee, and Operating Committee for review. Emergency LRP, Reporting. PJM reports alternative measurement methods (for load reductions). PJM intends to study alternative methods on a case-by-case basis during the life of the program and report the results. ELRP, Alternative Methods.

Organization	Summary	Research
		PJM submits to FERC two reports (May 31 & Oct. 31) that review and evaluate the Economic Load Response Program, as well as reports: (1) names of those end-use customers who indicated that distributed generation would be run in support of the load reduction program to the EPA, together with the permitting information that was supplied upon registration; and (2) annually, a summary of the status of the program, having first sent it to the Board, Members Committee, Reliability Committee, Energy Market Committee, and Operating Committee for review. EconomicLRP, Reporting. *See also PJM Interconnection, LLC*, 104 FERC ¶ 61,188 (2003); *PJM Interconnection, L.L.C.*, 106 FERC ¶ 61,271 (2004).
SPP	A report on the efficiency of operational arrangements OATT modifications Operating budget Feasibility study of 1 control area Transmission cost allocation plan Seams agreement Schedule 1 Scheduling Charges	In the February 10, 2004 order, the Commission granted SPP RTO status subject to the following reporting requirements. *See SPP*, 106 FERC ¶ 61,110. SPP is required to file a report evaluating the efficiency of its operational arrangements within 2 years of RTO effectiveness. SPP must file an operating budget within ninety (90) days of the date that SPP obtains operational authority over transmission facilities within its footprint, for informational purposes, consistent with our determination in Ameren Services. *See Ameren Services Co., et al.* 103 FERC ¶ 61,178, *clarification granted*, 104 FERC ¶ 61,097 (2003) *reh'g denied*, 105 FERC ¶ 61,018 (2003) (requiring an information filing of the operating budget to give the parties and the Commission advance notice of potential cost issues). SPP filed an Operational Authority White Paper (OA White Paper) and a map of the SPP footprint in its compliance filing. However SPP still must provide a list of all transmission facilities that will be transferred to its operational control and must revise the OA White Paper or the Membership Agreement, or provide some other binding document, to reflect SPP's clear and sufficient authority to exercise day-to-day operational control over the appropriate transmission facilities within its footprint. This must include a detailed description of its proposed allocation of responsibilities between SPP and the control areas and the capabilities of each entity to perform its proposed responsibilities, and adopt the NERC classifications of service functions. If SPP chooses to set forth its operational authority in the OA White Paper, or some other document, its must incorporate those documents by reference in the Membership Agreement and file those documents under section 205 of the FPA. *See SPP*, 108 FERC ¶ 61,003 at P 62-64 (2004). SPP is required to study the feasibility of reducing its control areas and file the outcome

Organization	Summary	Research
		of its study to the Commission, by February 10, 2005, i.e. one year from the date of the order granting RTO status. SPP must make a compliance filing to include: (1) disclosure of the magnitude of load that is proposed to be grandfathered wholesale as well as bundled retail load and to indicate what percentage of these loads will be to the total load served under SPP's tariff, and (2) a schedule for converting its GFAs to the SPP OATT, consistent with the guidance provided to the Midwest ISO, to facilitate market operations. Prior to conversion, the rates, terms and conditions, of the GFAs will be honored. SPP must develop and file a transmission cost allocation plan by the end of this year. This plan should address pricing treatment for the projects identified in SPP's transmission plan. Regarding generator interconnection pricing proposals, SPP should follow compliance procedures to Docket No. RM02-1-000, Standardization of Generator Interconnection Agreements and Procedures. SPP must refile a seams agreement pursuant to section 205 and must provide detail on how SPP and Midwest ISO will coordinate RTO operations including, but not limited to the following: (1) procedures for ensuring Available Flowgate Capacity (AFC) and Available Transfer Capacity (ATC) are calculated consistently, coordinated on a multi-system basis and published to all market participants; (2) procedures for developing consistent treatment of Transmission Reliability Margin (TRM) and Capacity Benefit Margin (CBM); (3) Type, and timing, of information exchange related to AFC, ATC, TRM and CBM; (4) Procedures for coordinating emergency and restoration procedures, prevention of system collapse and instability; (5) procedures for coordinating operational model data updates and exchanging such data; and (6) details on notification and coordination of maintenance outaqges of generation and transmission lines impacting inter-RTO transfer capability. *See SPP*, 108 FERC ¶ 61,003 at P 53 (2004) In the March 19, 2004 order the Commission directed SPP to make a filing, within thirty days of the date of this order, revising its OATT to reflect the Commission's Order No. 2003 *pro forma* LGIP and LGIA. The filing submitted in compliance with the instant order will serve as SPP's LGIP and LGIA until the Commission takes further action in this proceeding once SPP's status is finalized. *See SPP*, 106 FERC ¶ 61,254. SPP's April 19 compliance filing was conditionally accepted subject to SPP submitting a further compliance filing deleting the words "and within Commission policy" from section 1.0 of the Allocation Agreement.

Organization	Summary	Research
		SPP must file a report addressing the issues concerning the purchase of reactive power and Schedule 1 rate pancaking with interested parties by February 10, 2005, and must make a progress report by September 2, 2004.

Treatment of Non-Public Utility
Issue # 9

Organization	Summary	Research
CAISO	CAISO is not obliged to accept schedules, adjustment bids or bids for ancillary services which would require Energy to be transmitted to or from the distribution system of UDC directly connected to the CAISO Controlled Grid unless the relevant UDC has entered into a UDC Operating Agreement. During system emergencies, UDCs will comply with all directions from CAISO. Each UDC and the Participating TO with which it is interconnected will coordinate in the planning and implementation of any expansion or modification of a UDC's or Participating TO's system that will affect their transmission, the CAISO Controlled Grid or the transmission services to be	Non-public utilities have the same exit rights as all other participants. CAISO is not obliged to accept schedules, adjustment bids or bids for ancillary services which would require Energy to be transmitted to or from the distribution system of a Utility Distribution Company (UDC)[14] directly connected to the CAISO Controlled Grid unless the relevant UDC has entered into a UDC Operating Agreement. CAISO Tariff Appendix A: Master Definitions Supplement. In the event of system emergencies, UDCs will comply with all directions from CAISO concerning the management and alleviation of the System Emergency and will comply with all procedures concerning System Emergencies set out in the CAISO Protocols. CAISO Tariff § 4.4. CAISO has the authority to direct a UDC to disconnect load from the CAISO Controlled Grid if necessary to avoid an anticipated System Emergency or to regain operational control over the CAISO Controlled Grid during an actual System Emergency. CAISO Tariff § 4.4.4. Each UDC and the Participating TO with which it is interconnected will coordinate in the planning and implementation of any expansion or modification of a UDC's or

[14] A UDC is an entity that owns a distribution system for the delivery of Energy to and from the CAISO Controlled Grid, and that provides regulated retail electric service to eligible customers, as well as regulated procurement service to those End-Use Customers who are not yet eligible for direct access, or who choose not to arrange services through another retailer.

Organization	Summary	Research
	required by the UDC. CAISO and each UDC will enter into an agreement in relation to the operation and maintenance of the UDC's facilities which are under CAISO's operational control. CAISO will not schedule energy or ancillary services by any UDC otherwise than through a Scheduling Coordinator. Publicly Owned Electric Utilities whose transmission facilities are under CAISO operational control will file with the Commission their proposed High Voltage Transmission Revenue Requirements, and any proposed changes to it. Local Publicly Owned Electric Utility retail transmission service rates will be determined by the local regulatory authority and submitted to CAISO for informational purposes only.	Participating TO's system that will affect their transmission, the CAISO Controlled Grid or the transmission services to be required by the UDC. The Participating TO is responsible for coordinating with CAISO. CAISO Tariff § 4.7. CAISO and each UDC will enter into an agreement in relation to the operation and maintenance of the UDC's facilities which are under CAISO's operational control. CAISO Tariff § 4.9. However, CAISO will not schedule energy or ancillary services by any UDC otherwise than through a Scheduling Coordinator. CAISO Tariff § 5. Publicly Owned Electric Utilities whose transmission facilities are under CAISO operational control will file with the Commission their proposed High Voltage Transmission Revenue Requirements, and any proposed changes to it, under procedures the Commission determines to be applicable. CAISO Tariff § 7.1.1. Local Publicly Owned Electric Utility[15] retail transmission service rates will be determined by the local regulatory authority and submitted to CAISO for informational purposes only. CAISO Tariff § 7.1.5.
MISO	Non-public utility members of Midwest ISO, *e.g.*, municipalities and rural electric cooperatives, are treated in the same manner as public utility members. The Western Area Power Administration participates based on specific	

[15] A Local Publicly Owned Electric Utility is a municipality furnishing electric service, a municipal utility district furnishing electric service, a public utility district furnishing electric services, an irrigation district furnishing electric services, a state agency or subdivision furnishing electric services, a rural cooperative furnishing electric services, or a joint powers authority that includes one or more of these agencies and that owns generation or transmission facilities, or furnishes electric services over its own or its members' electric distribution system.

Organization	Summary	Research
	congressional authority. Participation by independent transmission companies that are not public utilities, and therefore public power, is authorized subject to state laws and regulations and public power rate schedules.	
NYISO	Non-public utilities may participate in NYISO without fear that their may lose any special tax status.	
ISO-NE	Join the Publicly Owned Entity Sector. Entitled to designate a voting member of each Principal Committee. Publicly Owned Entities have a separate Financial Assurance Policy. Same exit rights as other Participants.	
PJM	Municipal members can make use of certain waiver provisions. PJM may request additional information as part of the overall financial review process of cooperatives and municipalities.	A Member who is a municipal electric system may seek a waiver from OA sections 5.1(b) (Working Capital, Capital Contributions) and 16.1 (Liability, Indemnity of Members) if such provisions cannot be lawfully applied to the Member. OA, 17.2. Municipal utilities and cooperatives utilizing facilities at voltage levels below 69 kV are considered on a case-by-case basis, and assigned monthly rates accordingly. Tariff, Attachment H-8A. Both in the initial and ongoing credit evaluation of cooperatives and municipalities, PJM may request additional information as part of the overall financial review process and will consider other alternative measures in determining financial strength and creditworthiness. Tariff, Attachment Q (PJM Credit Policy), I., II.
SPP	None	

Information Sharing
Issue # 10

Organization	Summary	Research
CAISO	CAISO, Participating TOs and UDCs will share information necessary to conduct necessary system planning studies. CAISO, the MSS Operator and Participating TOs will share information necessary to conduct system planning studies.	CAISO, Participating TOs and UDCs will share information such as projected load growth and system expansions necessary to conduct necessary system planning studies to the extent that these may impact the operation of the CAISO Controlled Grid. CAISO Tariff § 4.8.1. CAISO, the MSS Operator and Participating TOs will share information such as projected load growth and system expansions necessary to conduct system planning studies to the extent that these may impact the operation of the CAISO Controlled Grid. CAISO Tariff § 23.13.1.
MISO	As a condition of accepting the RTO choices of the former Alliance Companies, the Commission required PJM and Midwest ISO to enter into a Joint Operating Agreement (JOA) which must provide for extensive information sharing. The JOA between Midwest ISO and PJM has been submitted to the Commission and was accepted in 106 FERC ¶ 61,251 (2004). The Midwest ISO is also in the process of executing and filing a JOA with SPP. The Midwest ISO's proposal to share information with other parties is subject to further fillings and review by the Commission.	The Commission rejected large sections of the Midwest ISO's proposal to share information with other parties, including state commissions. The Midwest ISO must work with its stakeholders to more closely align its confidentiality proposal with PJM's. Since the Midwest ISO and PJM are moving toward a joint and common market, it will become increasingly important that they have a common means of sharing data with each other and with state commissions. The JOA between the Midwest ISO and PJM was accepted in 106 FERC ¶ 61,251 (2004). The Commission rejected Midwest ISO's proposal to share information with state commissions. *See* 108 FERC ¶ 61,163 (2004). The Commission recently granted the Organization of MISO states' request for 120 days to make an offer of proof regarding why the Midwest ISO proposal to share data with the state commissions should be acceptable. *See* 108 FERC ¶ 61,321 (2004). The resolution of this issue is on hold pending further filings. The Midwest ISO also has a JOA with SPP and SPP must file a revised JOA with the Midwest ISO that addresses market-to-nonmarket issues, including congestion management and coordinated flowgates by December 1, 2004, or SPP must file an executed version of the draft JOA submitted by the Midwest ISO. *See Southwest Power Pool, Inc.*, 109 FERC ¶ 61,010 (2004). As a condition of accepting the RTO choices of the former Alliance companies, and in furtherance of a common market, the Commission required PJM and Midwest ISO to enter into a Joint Operating Agreement (JOA) which must provide for extensive information sharing. The Commission directed PJM and Midwest ISO to post information concerning the operational and financial impact on market participants of adding new members to the respective organizations. National Grid, Midwest ISO and PJM were directed to describe how they intend to use technology or introduce

Organization	Summary	Research
		technology to enhance monitoring abilities and management of the grid. *Alliance Companies, et al.*, 100 FERC ¶ 61,137 (2002) (July 31 Order), *reh'g denied*, 103 FERC ¶ 61,274 (2003) (June 4 Order). The July 31 Order did not establish a deadline for the filing of the JOA.[16]
NYISO	NYISO has rules governing the access and use of confidential information.	Article 6 of NYISO's Market Administration and Control Areas Service Tariff provides rules for governing the access and use of confidential information. The ISO may request, and the customer shall provide, confidential information consistent with the disclosure requirements set forth in the ISO Service Tariff. The ISO shall use reasonable procedures to prevent the disclosure of confidential information and shall not publish, disclose or otherwise divulge confidential information to any person or entity without the prior written consent of the party supplying such confidential information, except as provided for under the ISO Market Power Monitoring Plan. The provisions of this section shall not apply to any confidential information: (i) which was in the public domain at the time of disclosure hereunder; (ii) which thereafter passes into the public domain by acts other than the acts of the ISO; or (iii) that the ISO is required to make publicly available by the Commission, the PSC or other legal process, or for reliability purposes pursuant to Good Utility Practice. A customer may request that the ISO keep confidential from another entity confidential information that the other entity does not require to perform its obligations and duties hereunder. The customer must state in writing that the information is to be treated as confidential information and the reasons for treating it as confidential information, otherwise information will be treated as non-confidential information. The ISO shall use confidential information for the exclusive purpose of performing its obligations hereunder and under any Service Agreement. The ISO will treat this information in conformity with the standards of conduct contained in part 37 of the Commission's Regulations and the Code of Conduct set forth in Attachment F to the ISO OATT. Pursuant to Commission requirements, the ISO shall make public bid information from the Energy, Capacity and Ancillary Services markets (but not the names of the bidders

[16] The JOA submitted and pending in Docket No. ER04-375-000 provides for the exchange of the following types of data and information between PJM and Midwest ISO on a continuous, real-time basis: Real-Time and Projected Operating Data, SCADA Data, EMS Models, Operations Planning Data, Planning Information, Models, provides for coordination of schedules, dispatch and curtailment for transactions with impacts across the seam.

Organization	Summary	Research
		making these bids) six-months after the bids are submitted. The ISO shall post the data in a way that permits third parties to track each individual bidder's bids over time. Prior to such disclosure, bid information submitted to the ISO by Market Participants shall be considered confidential information.
ISO-NE	NEPOOL Information Policy governs information sharing. Confidential Information can only be used to perform RTO functions. Confidential Information is secret and Participant-specific. Non-Participants also have Confidential Information. Public Information and Non-Confidential Information may be shared. Bankrupt Participants' Confidential Information is shared. Public information includes public reports, filings, and bid information. Certain non-public information may be shared with Reliability Councils and NEPOOL Participants if it serves to make the RTO function properly. Certain non-public, Participant-specific information may be shared with agents of that Participant. Asset specific information may be shared with Participants who are owners of the Asset. Meter and bid data may be shared with	ISO-NE and NEPOOL both operate according to the NEPOOL Information Policy, which establishes rules and guidelines regarding the appropriate disclosure of all information received, created and distributed in connection with the operation of and participation in NEPOOL. NEPOOL Information Policy, section 1, Page 3. Confidential Information is the sole and exclusively property of the Participant, and may only be used by ISO-NE and NEPOOL Committees in order to perform their obligations under the Tariff and NEPOOL Agreement. NEPOOL Information Policy, section 2.0, Page 5. Confidential Information is information that: (1) is furnished by a Participant or a NEPOOL Committee to ISO-NE or NEPOOL Committees; (2) constitutes trade secrets or commercial or financial information, the disclosure of which would harm the Participant or prejudice the Participant's position in the NEPOOL markets; and (3) has been designated in writing by the Participant, or by ISO-NE, as confidential. Confidential Information also includes information that: (1) is furnished by a non-Participant that takes part in a demand response program to ISO-NE or NEPOOL Committees; (2) constitutes trade secrets or commercial or financial information, the disclosure of which would harm the demand response information provider or prejudice the demand response information provider's position in the demand response program; and (3) has been designated in writing by the demand response information provider as confidential. NEPOOL Information Policy, section 2.1, Page 5. Information that is shareable is any information that: (1) is or becomes generally available to the public without any party violating any obligation of secrecy relating to the information disclosed; or (2) is received by a Participant in good faith from a third party who discloses such information on a non-confidential basis without violating any obligation of secrecy; or (3) is defined as "Public Information"; or (4) can be shown by the recipient's prior records to have been already known to the recipient other than through disclosure by a third party. NEPOOL Information Policy, section 2.1, Page 6. Any Participant that is the subject of a bankruptcy petition or that has otherwise defaulted under its NEPOOL arrangements, the following information will be disclosed by ISO-NE: (1) the type and amount of available financial assurance; (2) notification provided by the Participant to ISO-NE or NEPOOL Committees of a material change in

Organization	Summary	Research
	the Assigned Meter Reader. Reliability Operations and Area Control Information may be shared with External Control Center personnel. Internal (Satellites) Control Center Information may be shared with Satellite personnel. Load Response Provider Information may be shared with Load Response Provider personnel. ISO-NE information may be shared with ISO-NE personnel, consultants, counsel, and board members.	its financial status; (3) any change in the type or available amount of financial assurance provided by the Participant; (4) whether the Participant has defaulted on its payment obligations; (5) whether the Participant has defaulted on its obligations under the Financial Assurance Policy; (6) whether ISO-NE has provided notice of default to the surety; (7) whether the Participant is a net seller or purchaser; (8) the amount of the Participant's purchases; and (9) whether the Participant owns a registered Load Asset. NEPOOL Information Policy, section 2.3, Page 8. Public information, free for ISO-NE to share with the public at large, includes: (1) public record filings with regulatory agencies; (2) data posted on the OASIS; (3) information and reports that are required to be filed with the Commission, unless specified to be filed on a confidential basis; (4) public generator information including system inventory and new applications; (5) public market information, defined as items made public by the NEPOOL Filed Documents, or documents that are or have been approved by NEPOOL, or the items listed in Aggregate Market Results; (6) bid and offer information for all markets; (7) market test information; (8) system aggregate planning data including load forecasts; (9) public reports required by the NEPOOL Approved Documents; and (10) public market monitoring information. NEPOOL Information Policy, section 3.0(a), Page 10. Non-public transmission information, free for ISO-NE to share with Reliability Councils and all NEPOOL Participants' Transmission Personnel, includes: (1) information and reports filed with NERC or NPCC; (2) information relating to specific generating facilities which is required by transmission personnel to ensure the reliable operation of the New England bulk power system; (3) information related to the transmission system; (4) NEPOOL transmission operating guides; and (5) information related to system restoration efforts. NEPOOL Information Policy, section 3.0(b), Page 11. Participant specific data, free for ISO-NE to share with active users or agents of the specified Participant, includes: (1) data not yet posted on OASIS; (2) confidential information for which this Participant or agent thereof has the right to receive; and (3) invoice and settlement data. NEPOOL Information Policy, section 3.0I, Page 12. Asset specific information, free for ISO-NE to share with Participants, or agents thereof, who are joint owners and/or Entitlement Holders in the Asset, includes: (1) near real-time information related to the particular asset; (2) unit forecast information relating to a particular Asset, which is necessary to determine the projected operation of particular generators; (3) information relating to a particular asset, which is necessary to

Organization	Summary	Research
		determine the accuracy of settlement; (4) participant input data; (5) capability responsibility data and calculations; and (6) all information, excepting bids, offers, and meter data, necessary to verify settlement data. NEPOOL Information Policy, section 3.0(d, e), Page 12. Meter, bid, and offer data, free for ISO-NE to share with the Assigned Meter Reader for a specified Asset, includes: confidential information submitted as input to the Market System. NEPOOL Information Policy, section 3.0(f), Page 13. Reliability Operations, and Area Control Information, free for ISO-NE to share with External Control Center personnel, includes: (1) all system operations or planning information that relates to the particular external Control Center; (2) information that is required to assure the reliable operation of the interconnected bulk power system; (3) inter-area transmission operating guides that relate to the particular external control area; and (4) confidential information and non-confidential information may be shared for the purposes of increasing markets coordination. NEPOOL Information Policy, section 3.0(g), Page 14. Internal (Satellites) Control Center Information, free for ISO-NE to share with Satellite personnel, includes: (1) all system operations or planning information; (2) information relating to specific generating facilities that is needed to assure the reliable operation of the NEPOOL Control Area; (3) transmission operating guides; and (4) NEPOOL and Satellite System Restoration Plans. NEPOOL Information Policy, section 3.0(g)(ii), Page 15. Load Response Provider Information, free for ISO-NE to share with Load Response Provider personnel, includes: (1) retail customer information; (2) customer data; and (3) load profiles. NEPOOL Information Policy, section 3.0(h), Page 16. ISO-NE information, free for ISO-NE to share with ISO-NE personnel, consultants, counsel, and board members, includes: (1) any participant or asset specific information as requested by the ISO, which will be maintained in accordance with the NEPOOL Information Policy; and (2) any ISO administrative information. NEPOOL Information Policy, section 3.0(i), Page 16.
PJM	PJM's Office of the Interconnection (OI) oversees information sharing with regard to the PJM control area.	PJM's Office of the Interconnection (OI) furnishes information and reports to Members with regard to the outlook for, the functioning of, and results achieved by the PJM Control Area or PJM West Region. OA, 10.4. No Member has the right to receive or review confidential information of another

Organization	Summary	Research
		Member, except that a Member may receive composite documents insofar that such composite information does not disclose any individual Member's confidential data or information. OA, 18.17.1(a). OI does not disclose confidential information (including documents, data) of a Member or an entity applying for Membership to Members or third parties, except: (1) OI may provide such information to its agents, representatives, or contractors to the extent that these are bound by an obligation to maintain confidentiality; and (2) OI may provide such information to the North American Electric Reliability Council (NERC) or any regional reliability council in its reasonable discretion provided that: (a) such information is needed to enhance and/or maintain reliability with MAAC and its neighboring reliability councils; (b) the entity is obliged to maintain confidentiality; and (c) OI notifies the affected party of its intention to disclose no less than 5 business days prior to the release. OA, 18.17.1(b). OI can release a Member's confidential information with that Member's specific, written authorization. OA, 18.17.1(c). OI discloses a Member's confidential information to third parties other than the Commission when required by law, provided that OI notifies the affected Member; the affected Member may direct any challenge or defense to such disclosure at the Member's expense; OI cooperates with the affected Member to the maximum extent practicable. OA, 18.17.2(a). OI discloses requested confidential information to the Commission, but requests that such information be treated as confidential and non-public; OI notifies the affected Member(s) of the request by FERC for, or of the decision by FERC to disclose confidential information. OA, 18.17.3. OI shall protect confidential information. OA, Schedule 1, 1.6.2(viii). The OI may disclose confidential information to an Authorized (State) Commission only if: (i) it has executed with the OI a Non-Disclosure Agreement, prohibiting the recipient from sharing such information with third parties and the Authorized Commission; (ii) provides the OI with a final Commission order prohibiting release of disclosed information under terms of the OA and the Non-Disclosure Agreement; and (iii) any other necessary orders issued by the Authorized (State) Commission and state

Organization	Summary	Research
		certifications. OA, section 18.17.4. *See also PJM Interconnection, LL.C.*, 107 FERC ¶ 61,322 (2004). OI produces special reports reasonably requested by the Members Committee; such reports do not disclose confidential or commercially sensitive information. OA, Schedule 1, 1.6.3. OI may disclose information to the Members Committee for review with regard to a dispute, provided that disclosure complies with confidentiality and other non-disclosure requirements. OA, Schedule 1, 1.8.2(c),. PJM submits annual reports to the Commission on behalf of the Economic and Emergency Load Response Program participants, and posts the same on the PJM web site. Economic LRP, Reporting; Emergency LRP. Party producing information pursuant to an arbitral proceeding may designate such information confidential. Schedule 5, 4.9.1. Any party receiving a request or demand for disclosure of information obtained in an arbitration proceeding that has been designated confidential or subject to a non-disclosure requirement shall immediately inform the party from whom the information was obtained and take all reasonable measures to afford that party an opportunity to prevent disclosure. Schedule 5, 4.9.2. Public information can be disclosed, even if it was also obtained within an arbitral proceeding. Schedule 5, 4.9.3. OI posts calculations of unhedgeable congestion on PJM's Internet site. Schedule 6, 1.5.7(c)(5). With regard to PJM Capacity Credit Market data, OI does not disclose commercially sensitive or proprietary information in any report or web site posting. Schedule 11, 4.2. Terms and conditions of: (1) all Sell Offers and Bid Buys; and (2) any bilateral transactions for capacity or Capacity Credits, are confidential information. Schedule 11, 5.8.
SPP	Public registry of all non-classified facilities	SPP shall maintain a publicly available registry of all facilities that are not classified as critical energy infrastructure information that constitute the Electric Transmission System. *See* Membership Agreement 2.1.1c. and 106 FERC ¶ 61 110

Organization	Summary	Research
	Electronic databases of information are controlled by Membership Agreements Confidentiality of member specific technical data governed by Membership Agreements Member specific non-propriety data is available with notice to Member when information is released. Planned maintenance schedules are confidential SPP has access to transmission owner's books and records for audits.	SPP shall publish and distribute printed reports as necessary to fulfill the SPP mission. SPP shall also develop and maintain electronic data bases of relevant technical information as approved by the Board of Directors. The release of information in databases containing member-specific technical data considered proprietary in nature will be governed by the Membership Agreement and related Criteria and administered by the Staff. In the event member specific non-proprietary technical data is being distributed, SPP will provide written notice of the specific data submitted, to whom it is being submitted and the purpose of such submittal to the respective Member at the same time the data is provided to the requesting party. Publications and technical data will be made available at no charge to Members, other regional councils and their members, and federal and state agencies. *See* SPP Bylaws section 3.12. Members shall provide such information to SPP as is necessary for SPP to perform its obligations under this Agreement and the OATT, and for planning and operational purposes. Such information shall be treated as confidential when so designated so long as its designation is reasonable. *See* Membership Agreement section 3.15 Transmission Owner shall grant SPP such access books and records as is necessary for SPP to perform its obligations under this Agreement and to audit and verify transactions under this Agreement. Such access shall be at reasonable times and under reasonable conditions. Transmission Owner shall not be required to provide access to confidential information unless it consents, which consent will not be unreasonably withheld. Transmission Owner may require reasonable disclosure conditions before giving its consent. Disclosure of confidential information shall be made consistent with such disclosure conditions or in accordance with any effective order requiring production of such confidential information issued by a court or regulatory authority. SPP shall provide Transmission Owner immediate notice of any request by an entity to review any such confidential information. *See* Membership Agreement section 3.7. An SPP Organizational Group may limit attendance at a meeting by an affirmative vote of the Organizational Group as necessary to safeguard confidentiality of sensitive information, included but not limited to Order No. 889 Code of Conduct requirements, personnel, financial, or legal matters. *See* SPP Bylaws, section 3.5 The executive sessions are open only to directors and to parties invited by the Chair and are held as necessary upon agreement of the Board of Directors to safeguard confidentiality of sensitive information regarding employee, financial, or legal matters. *See* Exhibit No. SPP-3, section 4.6.5 of the revised Bylaws.

Organization	Summary	Research
		Planned Maintenance Schedules shall be kept confidential. *See* Membership Agreement, section 2.1.4

Organization	Summary	Research
CAISO	CAISO no longer sponsors the Demand Relief Program or the Discretionary Load Curtailment Program. A SC may specify that loads will be reduced at specified market clearing prices or offer the right to exercise load curtailment to CAISO as an ancillary service or utilize load curtailment itself as non-spinning reserve or replacement reserve. CAISO may require direct control over such curtailment demand to assume response capability for managing system emergencies.	<u>Demand Response</u> - With the expanded demand response and conservation programs provided by the Investor Owned Utilities, the California Energy Commission, California's Consumer Power and Conservation Financing Authority (California Power Authority), and the CPUC, CAISO no longer sponsors the Demand Relief Program or the Discretionary Load Curtailment Program. The CAISO Participating Load Program (Supplemental and Ancillary Services) continues year round as usual. Details of the Participating Load Program are included on the CAISO Demand Response Web page: http://www.caiso.com/clientserv/load/ <u>Use of Load Curtailment Programs</u> - As an additional resource for managing System Emergencies, CAISO will, subject to section 2.1.3, notify the UDCs when the conditions to implement their load curtailment programs have been met. Each UDC will by not later than October 1 of each year advise CAISO of the capabilities of its load curtailment programs for the forthcoming year, and the conditions under which those capabilities may be exercised and will give CAISO as much notice as reasonably practicable of any change to such program. CAISO Tariff § 2.3.2.8.1. <u>Load Curtailment</u> – A SC may specify that loads will be reduced at specified market clearing prices or offer the right to exercise load curtailment to CAISO as an ancillary service or utilize load curtailment itself (by way of self provision of ancillary services) as non-spinning reserve or replacement reserve. CAISO may require direct control over such curtailable demand to assume capability for managing System Emergencies. CAISO Tariff § 2.3.2.8.2. *See also* CAISO Tariff, Dispatch Protocol.
MISO	Midwest ISO has Demand Response resources for curtailment only. Midwest ISO will utilize demand response resources to ensure reliability and to address issues of the demand to react to prices in support of reliability.	Midwest ISO implemented demand response resources in its March 30, 2004 TEMT filing. Midwest ISO defined demand response resources as loads that can respond to dispatch instructions in real time or to high prices in the day-ahead market. Demand response resources will be allowed to participate in the markets in a manner comparable to generation resources, provided that they comply with the requirements necessary for the Midwest ISO to validate their ability to respond as intended. The Commission approved the use of demand response resources, provided that the Midwest ISO provide further details on how it intends to measure the response of the DRRs ans several other issues that the Commission wants the Midwest ISO to clarify. *See* 108 FERC ¶ 61,163 (2004).
NYISO	NYISO has three types of demand response program: (1) Day-Ahead	NYISO currently has three demand response programs. They are: (1) the day-ahead demand response program, which permits demand resources to submit demand

Organization	Summary	Research
	Demand Response Program; (2) Emergency Demand Response Program; and (3) Installed Capacity/Special Case Resource Program.	reduction bids in the day-ahead market; (2) the emergency demand response program, under which qualified demand resources are paid for reducing their energy consumption when NYISO declares that an operating reserves deficiency or major emergency exists; and (3) the Installed Capacity/Special Case Resource program, under which retail electricity customers are paid in advance for agreeing to curtail usage during times when the reliability of the grid could be jeopardized. Under these various programs, eligible customers (a/k/a curtailment service providers) must provide metering data to allow verification of their demand reduction performance. *See e.g.* 105 FERC ¶ 61,115 (2003). For specific details regarding NYISO's Emergency Demand Response Program, *see* Attachment G of the *Market Administration and Control Areas Service Tariff*.
ISO-NE	ISO-NE has a Load Response Program in place. The LRP is a five-part program. Demand Resources and Price Responses may not span multiple Load Zones. All programs require interval metering. Day-Ahead Demand Response Program caters to Resources that require more than 2 hours to curtail. Real-Time Demand Response Program Resources must be at least 100 kV and have an Internet-based communication system. Real-Time Price Response Program involves voluntary curtailments depending on price levels. Real-Time Profiled Response Program is for participants with loads that are capable of being interrupted on demand.	ISO-NE and NEPOOL have a Load Response Program that was designed to facilitate load response during periods of peak electricity demand by providing appropriate incentives. Load Response Program incentives are available to any Participant or Non-Participant which enrolls itself and/or one or more retail customers ("Demand Resources") to provide a reduction in their electricity consumption in the NEPOOL Control Area during peak demand periods. NEPOOL SMD, Appendix E, section 1.1, Substitute 2nd Rev Sheet No. 601. The Load Response Program is comprised of: (1) Day-Ahead Demand Response Program; (2) Real-Time 30 Minute Demand Response Program; (3) Real-Time 2 Hour Demand Response Program; (4) Real-Time Price Response Program; and (5) Real-Time Profiled Response Program. Demand Resources are only eligible to participate in one program at a time, except that a Demand Resource participating in the Day-Ahead Demand Response Program whose offer is not accepted in the Day-Ahead Energy Market, may participate in the Real-Time Price Response Program. Generating Resources that are already qualified as generating assets are not eligible for the Load Response Program. NEPOOL Standard Market Design, Appendix E, section 1.2, 2nd Rev Sheet No. 601. The costs of Real-Time Load Response Programs will be allocated to the applicable Real-Time Load Obligation on a system wide basis (commencing on the SMD Effective Date), except for costs associated with the communication system. Commencing on the date that the Day-Ahead program is implemented, the allocation of the Load Response Program costs will change from Load Obligation to Network Load on a system wide basis. To the extent that a program participant's bid in the Day-Ahead Demand Response Program clears (is accepted), any charges or credits

Organization	Summary	Research
		associated with such deviations will be allocated to the program participant. NEPOOL Standard Market Design, Appendix E, section 1.4, 2nd Rev Sheet No. 93 A Demand Resource cannot span multiple Load Zones. A Price Response customer cannot span multiple Load Zones. All programs, except the Profiled Response Program, require interval metering. With the exception of the Profiled Response Program and "Super" Low-Tech option of the Real-Time Price Response Program, meters are read at least daily and some will require an Internet-based Communication System. NEPOOL Standard Market Design, Appendix E, section 1.5, 2nd Rev Sheet No. 93. Demand Resources that require more than 2 hours advance notice in order to curtail consumption may participate in the Day-Ahead Demand Response Program, as may Demand Resources that require less than 2 hours. Participants submit Supply Offers in the Day-Ahead Energy Market on behalf of a Demand Resource in increments of 1 MW or more. Resources may be aggregated to reach the 1 MW minimum. The minimum Supply Offer shall be $50/MWh and the maximum shall be $1,000/MWh. Demand Resources that participate in the Day-Ahead Demand Response Program are eligible to qualify as ICAP Resources. NEPOOL Standard Market Design, Appendix E, section 2, Substitute 1st Rev Sheet No. 603. To participate in the Real-Time Demand Response Programs, Demand Resources must be at least 100 kW in size, and must have use of an Internet-based Communication System. The ISO issues interruption instructions to Demand Resources on a zonal or system wide basis. Demand Resources participating in the 30 Minute Demand Response Program must respond within 30 minutes of the ISO's instructions to interrupt, while those participating in the 2 Hour Demand Response Program have 2 hours to interrupt. NEPOOL Standard Market Design, Appendix E, section 3, 1st Rev Sheet No. 93. Real-Time Price Response Program: Voluntary reductions are allowed when the forecasted hourly Zonal Price produced by the Day-Ahead Energy Market or any day-ahead unit commitment update, or in day is greater than or equal to $100/MW and the ISO has transmitted instructions that the eligibility period is open. Interval metering is required. NEPOOL Standard Market Design, Appendix E, section 4, 2nd Rev Sheet No. 93. The Real-Time Profiled Response Program is for participants with loads that are capable of being interrupted on demand. Participants in this program are willing and capable of responding in Real-Time to ISO instructions to interrupt load within a

Organization	Summary	Research
		specified time period. Participants in this program could include aggregated residential super-thermostat programs, pool pumps and distributed generation. A Participant aggregating Demand Resources for this program is required to provide a statistical response factor for the group. NEPOOL Standard Market Design, Appendix E, section 5, 1st Rev Sheet No. 94.
PJM	General Provisions	Two primary types of distributed resources are candidates to participate in the PJM Emergency and Economic Load Response Programs below: • On-Site Generators: These generators (including Behind-the-Meter Generation) can be either synchronized or non-synchronized to the grid. Exports to the grid by local generators will be eligible for compensation under this program only if such exports are allowed under any applicable interconnection agreements and PJM Tariff provisions. Capacity Resources are not eligible for compensation under this program. Injections into the grid by local generators also will not be eligible for compensation under this program. • Load Reduction: A participant that has the ability to reduce a measurable and verifiable portion of its load, as metered on an Electric Distribution Company (EDC) account basis. PJM membership is required to participate, although any existing PJM Member may act as an agent for non-members in which case the agent will be the CSP for the non-member. Emergency LRP, Participant Qualifications; Economic LRP, Participant Qualifications. The programs will be effective beginning December 1, 2004, and will remain in effect until December 31, 2007. Economic LRP, Effective Date; Emergency LRP, Effective Date.
	Emergency Load Response Program	The Emergency Load Response Program is designed to provide a method by which end-use customers may be compensated by PJM for voluntarily reducing load during an emergency event. Payment for reducing load is based on the actual kWh relief provided plus the adjustment for losses. PJM pays the higher of the appropriate zonal Locational Marginal Price (LMP) or $500/MWh to the PJM Member that nominates the load. Emergency LRP.
	Economic Load Response Program	The Economic Load Response Program is not based on the declaration of emergency conditions in PJM, but rather on the economic decisions of the PJM market participants. That is, the participants in the program are responsible for determining the conditions under which load reductions will actually take place and implementing the reductions should those conditions arise. The prime indicator of such conditions is assumed to be the LMP of energy on the PJM system.
	Economic Load Response Program –	

Organization	Summary	Research
	Real-Time Economic Load Response Program – Day-Ahead Behind-the-Meter Generation	This option will provide a mechanism by which any qualified Load Serving Entity (LSE) or Curtailment Service Provider (CSP) may offer end-use customers the opportunity to, or end-use customers that are PJM members independently may choose to, reduce load they draw from the PJM system during times of high prices and receive payments based on real-time LMP for the reduction. Economic LRP, Real-Time Operations. This option will provide a mechanism by which any qualified LSEs or CSPs may offer end-use customers the opportunity to, or end-use customers that are PJM members independently may choose to, commit to a reduction of load they draw from the PJM system in advance of real-time operations and receive payments based on day-ahead LMP for the reductions. Economic LRP, Day-Ahead The Commission permitted PJM to implement rules for behind the market generation, which allows select market participants to net operating behind the meter generation against load at the same electrical location for the purpose of calculating applicable PJM charges. The Commission determined that the total netting approach is consistent with the principle of cost causation and that it will encourage load response to generation or transmission scarcity and/or rising prices. PJM must file a status report by January 1, 2005, on its continuing examination of whether the netting program can be expanded to include some generators (e.g. municipalities) that are not at the same electrical location. *See also PJM Interconnection, LLC*, 107 FERC ¶ 61,113 (2004), *reh'g denied*, 108 FERC ¶ 61,032 (2004)
SPP		SPP does not appear to have any Demand Response Programs

Organization	Summary	Research
CAISO	The CAISO control area consists of the former control areas of the three Investor Owned Utilities (PG&E, SDG&E, and Southern California Edison), and the service areas of some of the Municipal Utility Districts. It does not include Sacramento (SMUD), Western Area Power Administration (WAPA) or Los Angeles (LADWP).	CAISO defines a control area as a "geographic area which regulates its generation in order to balance load and maintain planned interchange schedules with other control areas" (CAISO Summer Assessment, p. 40). Loosely, it is a portion of the grid over which a single entity has responsibility for maintaining the balance of supply and demand, and ensuring reliability. The CAISO control area consists of the former control areas of the three IOUs (PG&E, SDG&E, and Southern California Edison), and the service areas of some of the Municipal Utility Districts. It does not include SMUD, WAPA or LADWP. Within its control area, CAISO is responsible for scheduling generation and load, contracting for all the services necessary to maintain grid reliability, and dealing with any and all contingencies. To account for all the power that flows through the wires, they also need to keep tabs on how much electricity is entering and leaving through the borders of their control area.
MISO	Upon acceptance of Midwest ISO, the Commission expected that the number of control areas in Midwest could be significantly reduced. In February, 2003, the Commission directed Midwest ISO, within one year of the start of Day-2 operations, to file an assessment of any efficiency issues created by the continuation of the 40 control area structure. The Commission determined that Midwest ISO must have the ability to direct the actions of control areas through financially binding LMPs along with penalties for excessive deviations from dispatch instructions. The Commission advised Midwest ISO to	The Commission, in granting ISO status to Midwest ISO, stated its concerns about the relationship between control areas and Midwest ISO and the ISO's ability to provide reliable, non-discriminatory transmission service. The Commission initially required a detailed summary of Midwest ISO's operating and emergency procedures, and an assessment report within 18 months of commencement of Midwest ISO operations, noting that while it did not have any preconceived views of the appropriate operational solution for this region, the Commission expected that the number of control areas in Midwest could be significantly reduced, or other measures might be adopted to address any problems identified. *Midwest ISO, et al.*, 84 FERC ¶ 61,231 (1998) (September 16 Order), *order on reh'g*, 85 FERC ¶ 61,372 (1998). In a declaratory order issued February 24, 2003, the Commission directed Midwest ISO, within one-year of the start of Day-2 operations, to file an assessment of any efficiency and independence issues created by the continuation of the 40 Control Area structure, an analysis of merging control area functions in part or all of Midwest ISO (and thus reducing the number of control areas), a recommendation to the Commission for consolidating Control Areas and the timeframe for such operational integration should the analysis support such an outcome. The assessment would also include both the costs associated with continuing the 40 Control Area structure and consolidating

[17] The number of control areas in Midwest ISO varies according to whether the number includes only the larger members' control areas or all control areas, large and small, as well as pending membership applications. The number has also varied due to potential mergers, as with SPP, and the current pending application of GridAmerica.

Organization	Summary	Research
	state clearly which functions must be under its exclusive direction to ensure that reliability is maintained There are currently thirty-five (35) control areas in Midwest ISO.[17]	any Control Areas. *Midwest ISO*, 102 FERC ¶ 61,196 (2003) (Declaratory Order), *order on reh'g*, 103 FERC ¶ 61,210 (2003). (This requirement superceded the original requirement outlined in the September 16 Order.) In light of the August 14, 2003 blackout, ongoing disagreements about control area responsibilities, and a proposed Reliability Charter to be developed by Midwest ISO, the Commission determined that Midwest ISO must have the ability to direct the actions of control areas through financially binding LMPs along with penalties for excessive deviations from dispatch instructions, to successfully and reliably operate a centralized, bid-based dispatch market. The Commission advised Midwest ISO to state clearly which functions must be under its exclusive direction to ensure that reliability is maintained. The Commission also directed Midwest ISO to file, within three months of the date of the order, an informational update on progress. Finally, the Commission expressed support for consolidation of control area operations and reiterated its request included in the Declaratory Order for an evaluation of progress toward that goal within one year of Day 2 market start-up. *Midwest ISO*, 105 FERC ¶ 61,145 (2003) (October 29 Order), *reh'g denied*, 105 FERC ¶ 61,272 (2003). According to Midwest ISO CEO James Torgerson, there are currently thirty-five (35) control areas in Midwest ISO.[18]
NYISO	New York State	NYISO's New York Control Area (NYCA) encompasses the entire State of New York. The term "New York Control Area" is defined in section 2.110 of NYISO's *Market Administration and Control Areas Service Tariff* and section 1.26b of NYISO's *OATT*.
ISO-NE	New England Transmission Owners have their own OATTs and operate their own control areas. RTO-NE would maintain operational authority over bulk power now controlled by ISO-NE. Authority over Non-PTF Ties will be made in a supplemental filing.	The NEPOOL Control Area is the integrated electric power system to which a common Automatic Generation Control scheme and various operating procedures are applied by or under the supervision of the System Operator. Restated NEPOOL Agreement, section 1.74, Sheet No. 34. New England Transmission Owners have their own OATTs and operate their own control areas. They are: Boston Edison Co.; Bangor Hydro Electric; Commonwealth Energy Systems; Central Maine Power; Eastern Utilities Associates; New England Electric System; Northeast Utilities; United Illuminating; and Vermont Electric Light Co. NEPOOL Tariff, Attachment K, Original Sheet No. 327.

[18] (Presentation of Midwest ISO President and CEO James Torgerson to the Commission, December 17, 2003.)

Organization	Summary	Research
		The RTO-NE filing, pending Commission approval, provides that RTO-NE will exercise day-to-day operational authority over all of the bulk power transmission facilities that are currently controlled by ISO-NE through the dispatch of all interconnected generation, and hierarchical control over the region's transmission facilities. Request for Approval of Regional Transmission Organization for New England, Docket No. RT04-2-000, Page 82. RTO-NE's authority over the Non-PTF Ties will be clarified through a supplemental filing, including bilateral agreements with the owners of those facilities, to be submitted prior to the RTO-NE Operations Date. Request for Approval of Regional Transmission Organization for New England, Docket No. RT04-2-000, Page 83.
PJM	PJM's control area comprises 16 distinct areas/entities.	PJM comprises 16 control areas, to wit: American Electric Power Service Corporation, Atlantic City Electric Co., Baltimore Gas and Electric Co., Commonwealth Edison Co., Dayton Power & Light Company, Delmarva Power & Light Co., Jersey Central Power & Light Co., Metropolitan Edison Co., Pennsylvania Electric Co., Pennsylvania Power & Light Co., Potomac Electric Power Co., Public Service Electric and Gas Co., Allegheny Power, Rockland Electric Power, and Virginia Electric and Power Company (effective December 1, 2004). Tariff, Attachment J (PJM Transmission Zones).
SPP		All of Oklahoma, parts of Kansas, Missouri, New Mexico, Arkansas, Louisiana and Texas. SPP serves over 4 million customers over 33,000 miles of transmission lines, over 250,000 square miles with a load of 35,100 MW and 46,100 MW total generation Capacity.

Treatment of Transmission vs. Distribution or Non-Pool Transmission
Issue # 13

Organization	Summary	Research
CAISO	CAISO defines a "distribution system" as the distribution assets of an IOU or Local Publicly Owned Electric Utility. Unless an UDC has entered into an UDC Operating Agreement with the CAISO, the CAISO is not obligated to accept schedules, adjustment bids or bids for ancillary services that would require energy to be transmitted to or from a UDC directly connected to the CAISO Controlled Grid. CAISO will not schedule energy or ancillary services generated to the distribution system of a Participating TO or of a UDC otherwise than through a SC. A generator connected directly to a UDC distribution system that sells its entire output to the UDC in which the generator is located is not subject to the audit, testing or certification requirements of CAISO. Each SC will ensure that each of its SC Metered Entities connected to and served from the UDC will be metered by a revenue meter complying with Local Regulatory Authority or as set forth in CAISO Appendix J and the CAISO metering protocols.	As stated above, the CAISO control area consists of the former control areas of the three IOUs (PG&E, SDG&E, and Southern California Edison), and the service areas of some of the Municipal Utility Districts. It does not include SMUD, WAPA or LADWP. <u>CAISO treatment of distribution systems</u> - CAISO defines a "distribution system" as the distribution assets of an IOU or Local Publicly Owned Electric Utility. CAISO is not obliged to accept schedules, adjustment bids or bids for ancillary services which would require energy to be transmitted to or from the *distribution system* of a UDC directly connected to the CAISO Controlled Grid unless the UDC has entered into a UDC Operating Agreement. CAISO Tariff, section 4.1.1. CAISO will operate the CAISO Controlled Grid and each UDC will operate its distribution system at all times in accordance with Good Utility Practice. CAISO Tariff § 4.1.2. The ISO shall have the right by agreement to delegate certain operational responsibilities to the relevant Participating TO or UDC pursuant to section 4. All information made available to UDCs by the ISO shall also be made available to Scheduling Coordinators. All information pertaining to the physical state or operation, maintenance and failure of the UDC Distribution System affecting the operation of the ISO Controlled Grid that is made available to the ISO by the UDC shall also be made available to Scheduling Coordinators upon receipt of reasonable notice. CAISO will not schedule energy or ancillary services generated to the distribution system of a Participating TO or of a UDC otherwise than through a SC. CAISO Tariff section 5. A generator connected directly to a UDC distribution system that sells its entire output to the UDC in which the generator is located is not subject to the audit, testing or certification requirements of CAISO. CAISO Tariff, section 10.5.2. Each SC, in conjunction with the relevant Local Regulatory Authority, will ensure that each of its SC Metered Entities connected to and served from the distribution system of a UDC will be metered by a revenue meter complying with Local Regulatory Authority relevant standards, or, if no such standards have been set, the metering standards set forth in CAISO Appendix J and the CAISO metering protocols. CAISO Tariff, section

Organization	Summary	Research
		10.6.4. <u>Gross Load</u> – for purposes of calculating the transmission access charge (TAC), gross load is all energy (adjusted for distribution losses) delivered for the supply of loads directly connected to the transmission facilities or *distribution system* of a UDC or MSS. Gross load shall exclude load with respect to the portion of the load of an individual retail customer of a UDC, MSS or SC that is served by a generating unit that: (a) is located on the customer's site or provides service to the customers site through arrangements authorized by the California Public Utilities Code, section 218; (b) is a qualifying small power production facility or a QF; and (c) secures standby services from a Participating TO under terms approved by a Local Regulatory Authority or the Commission. In the case of a Local Publicly Owned Electric Utility that: (a) is a Participating TO; (b) is in compliance with all metering requirements; and (c) has not received a waiver of such metering requirements, gross load will also exclude the portion of the Local Publicly Owned Electric Utility's load that is served by a generating unit that: (a) is directly connected to load through the Local Publicly Owned Electric Utility's distribution system; (b) has certified and polled metering; and (c) is operated at greater than 50 percent capacity in the current month as measured by such a meter. CAISO Tariff, Appendix A.
MISO	Transmission owners in Midwest ISO transferred operation control of their jurisdictional facilities to Midwest ISO. Jurisdictional facilities include all networked transmission above 100 kV.	On September 16, 1998, the Commission conditionally approved the application of ten transmission-owning public utilities to transfer operational control of their jurisdictional transmission facilities to Midwest ISO. The Transmission Owners retained ownership of their transmission facilities, and physically operated and maintained these facilities, subject to Midwest ISO's direction. Under the Midwest ISO Agreement, all control area operators continued to operate their control areas for local generation control and economic dispatch purposes. However, the Transmission Owners were required to follow the directives of the ISO for redispatching generation, curtailing load, and providing reactive supply, voltage control or other ancillary services. *Midwest ISO, et al.*, 84 FERC ¶ 61,231 (1998). The transmission system of Midwest ISO is defined as the transmission facilities of the Owners which are committed to the operation of Midwest ISO, including: (i) all networked transmission facilities above 100 kV; and (ii) all networked transformers where the two highest voltages qualify under the 100 kV voltage criteria. The facilities may also include other facilities that Midwest ISO directs the Owner(s) to assign to it subject to procedures set forth in Appendix B of the Transmission Owners' Agreement.

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		The specific facilities are identified in Appendix H of the Transmission Owners' Agreement. Agreement of Transmission Facilities Owners to Organize the Midwest ISO, Article One (Issued November 20, 2000), Midwest ISO FERC Electric Tariff, First Revised Rate Schedule No. 1, Original Sheet No. 15-16, accepted by FERC on September 16, 1998.[19]
NYISO	The transmission facilities that are under the control of NYISO are listed on Appendix A-1 to the NYISO/TO Agreement.	The Transmission Owners have specified transmission facilities over which the ISO will have day-to-day Operational Control. These facilities shall be collectively known as the "Transmission Facilities Under ISO Operational Control," and are listed in Appendix A-1 of the NYISO/TO Agreement. The Transmission Owners also will be responsible for providing notification to the ISO with respect to actions related to other specified transmission facilities. These facilities shall be collectively known as "Transmission Facilities Requiring ISO Notification," and are listed in Appendix A-2 of the NYISO/TO Agreement. Transmission facilities may be added to, or deleted from, the lists of facilities provided in Appendices A-1 and A-2 by mutual written agreement of the ISO and the Transmission Owner owning and controlling such facilities.
ISO-NE	Each Participant must subject all generating facilities and other resources owned or controlled by it to central dispatch by the ISO. Each Participant which owns or operates pool transmission facilities or other transmission facilities rated 69 kV or above must subject all such facilities to central dispatch by the ISO.	Each Participant must subject all generating facilities and other resources owned or controlled by it to central dispatch by the ISO; provided that each Participant is at all times the sole judge as to whether or not and to what extent safety requires that at any time any of the facilities will be operated at less than full capacity or not at all. Restated NEPOOL Agreement, section 13.2, Sheet No. 158. Each Participant which owns or operates pool transmission facilities or other transmission facilities rated 69 kV or above must subject all such facilities to central dispatch by the ISO; provided that each Participant is at all times the sole judge as to whether or not and to what extent safety requires that at any time any of the facilities will be operated at less than full capacity or not at all. Restated NEPOOL Agreement, section 15.3, Sheet No. 203.
PJM	Operational authority over all transmission facilities under its control.	The OI determines whether local Transmission Facilities under its monitoring responsibility and dispatch control as of June 1, 2002, meet the PJM Reliability and Planning Criteria. Members with such local Transmission Facilities that do not meet

[19] Transmission service for all transmission facilities, and for wholesale distribution service, is provided under the MISO Tariff.

Organization	Summary	Research
		the PJM Reliability Criteria must either (1) remove the local Transmission Facilities from the dispatch control and monitoring responsibility of the OI within 60 days of notification by the OI of its determination that the local Transmission Facilities do not meet the PJM Reliability and Planning Criteria; or (2) commit, at their own cost and by completion date agreed to by the OI and the member, to reinforce the location Transmission Facilities to enable the local Transmission Facilities to meet the PJM Reliability and Planning Criteria. OA, Schedule 1. *See also PJM Interconnection, LLC, et al.*, 96 FERC ¶ 61,061(2001) (PJM's scope and operational authority); *PJM Interconnection, LLC*, 101 FERC ¶ 61,345 (2002).
SPP	All member transmission owners transferred functional control of transmission facilities to SPP.	The Revised Membership Agreement requires Member Transmission Owners to cede to SPP functional control over their transmission facilities, including: authority to schedule transactions, administer transmission services, review maintenance requests, control maintenance, monitor system loadings, voltages, the actions by market participants, and otherwise direct the tariff facilities. Section 1.19, 2.1.1a, 2.1.1k, and 3.0 of the Revised SPP Membership Agreement SPP evaluates and approves requests for transmission service, new interconnections, and directs the construction of transmission facilities. Sections 2.1.1d, 2.1.1g, 2.1.1j of the Revised SPP Membership Agreement SPP has authority to coordinate and direct reliability functions. Section 2.1.2 of the SPP Revised Membership Agreement and Tariff. SPP is the NERC approved reliability coordinator for its region and has the right to order redispatch of generation if necessary. Section 2.1.2(g) SPP Revised Membership Agreement SPP has the authority to approve or disapproval all requests for scheduled outages of transmission facilities, and if a transmission maintenance outage can compromise the integrity or reliability of the transmission system, SPP has the right to require modifications and/or rescheduling of planned maintenance. Section 2.1.3(b) Revised SPP Membership Agreement.

Interconnection

(Compliance with Order No. 2003)

Issue # 14

Organization	Summary	Research
CAISO	The Commission rejected CAISO's compliance filing on July 30, 2004. CAISO has 60 days to re-file and adopt the pro forma LGIP and LGIA. CAISO has requested a time extension for filing and has requested a rehearing. The Commission granted CAISO's extention of time request to comply with the Commission's July 30 Order until January 5, 2005. The Commission also clarified that the three PTOs must re-file their proposed changes to their TO Tariffs by January 5, 2005. As to the rehearing request, the Commission issued a tolling order granting rehearing for further consideration.	On July 30, 2004, the Commission rejected CAISO's compliance filing, because CAISO's changes did not meet either of the Commission's standards for deviation from the pro forma documents. The Commission determined that CAISO does not meet the independence requirement for ISO status; therefore, its compliance filing will not be reviewed under the "independent entity variation" standard. The Commission also determined that CAISO's changes cannot be accepted under the "consistent with or superior to" standard, because CAISO has not specifically explained how the changes meet this standard. Because of the procedural position CAISO is now in, the Commission has given CAISO 60 days to submit a compliance filing adopting the pro forma LGIP and LGIA. CAISO has filed for an extension of time for its compliance filing and has requested a rehearing on the Commissions rejection of its compliance filing.
MISO	On January 20, 2004, pursuant to the extension of time granted by the Commission to RTOs and ISOs, Midwest ISO submitted a compliance filing containing a pro forma interconnection agreement and procedures, with certain variations.	Under the more flexible, "independent entity" standard of Order No. 2003, on January 20, 2004, Midwest ISO submitted a new Attachment X containing both large generator interconnection procedures (LGIP) and the large generator interconnection agreement (LGIA) with certain variations from the terms of the *pro forma* LGIP and LGIA. The variations are intended to customize the interconnection agreement to accommodate transmission owners as signatories and to address issues not dealt with by Order No. 2003 that have been encountered by Midwest ISO. Midwest ISO, the Organization of MISO States, and other stakeholders continue discussions on a number of unresolved issues, including network upgrades and the potential use of a beneficiary-based cost allocation methodology. In addition, the Markets Subcommittee of Midwest ISO

Organization	Summary	Research
		Advisory Committee formed an Emergency Redispatch Generation Task Force to focus on Emergency condition services and compensation for those services. Midwest ISO requests an effective date of March 22, 2004. Midwest ISO Order No. 2003 Compliance Filing in Docket No. ER04-458-000.
NYISO		On January 20, 2004, NYISO filed its compliance with Order No. 2003 (Standardization of Large Generator Interconnection Procedures and Large Generator Interconnection Agreement) in Docket No. ER04-449-000. Also, on April 26, 2004, NYISO filed its compliance with Order No. 2003-A in docket No. ER04-449-002. On August 6, 2004, the Commission issued an order accepting both filings, subject to modification (*See* 108 FERC ¶ 61,159). Staff is currently reviewing hearing requests and requests for clarification relating to this order.
ISO-NE	The Commission accepted in part NEPOOL's Order 2003 compliance filing.	On November 8, 2004, the Commission accepted, in part, NEPOOL's Order 2003 compliance filing containing a *pro forma* Large Generator Interconnection Agreement and Procedures, with certain variations. ISO New England Inc., 109 FERC ¶ 61,155 (2004).
PJM		The Commission approved, with limited exceptions, the tariff revisions filed by PJM in order to comply with the requirements of Order No. 2003. *PJM Interconnection, L.L.C.*, 108 FERC ¶ 61,025 (2004). In this order, the Commission found that PJM, which does not own any generation facilities, is eligible for the more lenient "independent entity variation" standard. Under this standard, the Commission approved PJM's proposal with respect to deposits and billing for Facilities Studies, which varied from Order No. 2003's requirements. The Commission also directed PJM to make a subsequent compliance filing, modifying its tariff to conform to Order No. 2003's requirements with respect to liquidated damages and to explain the variance of its proposed tariff with the standard insurance provisions contained in Order No. 2003.
SPP		On January 20, 2004, SPP filed its compliance with Order No. 2003 in Docket No. ER04-434-000. On March 19, 2004, the Commission accepted and suspended for five months SPP's compliance filing subject to refund and further Commission order. Still under staff review. *See SPP*, 106 FERC ¶ 61,254.